TRANSMISSION PLANNING PROCESSES

Memorandum of

ONTARIO HYDRO

to the

Royal Commission
on Electric Power Planning

with respect to the

Public Information Hearings

JUNE, 1976

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12.0 Transmission Planning Processes

12.1 Introduction

Transmission planning is concerned with determining when new transmission facilities are required, what form these facilities should take, and their general location. Transmission planning requires a knowledge of the existing transmission system, a determination of future transmission requirements based on the forecast load and generation, and an evaluation of the options available to meet the requirements.

The objective is to plan a transmission system which has adequate reliability, can be readily adapted to changes in forecast conditions and which keeps costs and adverse effects on people and the ecology as low as practical. Transmission planning specifications deal with such requirements as capacity, loading patterns, insulation, operating levels and transient variations of voltage, short circuits and the required performance of protection and control equipment from a system standpoint. A major concern is the integrated performance of the generation-transmission system under normal and emergency operating conditions and under shock loadings imposed by electric faults.

This Memorandum summarizes many of the considerations involved in transmission system planning with particular emphasis on bulk power transmission. Transmission reliability which is a major consideration has been discussed in the Memorandum on Reliability and therefore is not considered here.

Other information on the technical aspects and environmental assessment of transmission lines and stations is contained in the Memoranda "Transmission-Technical" and "Transmission Environmental".

For planning and operating convenience, transmission lines are classed into four categories, according to their primary function.

Bulk power transmission lines

These are the main lines delivering power from generating stations to receiving terminal stations. They form the interconnected integrated system described in Section 12.2. On the existing Ontario Hydro system some of these lines operate at 500 kV

Area supply lines

These lines take power from the bulk power transmission system at the receiving terminal stations and transmit it to area-supply transformer stations located in or near cities and towns. The usual voltage levels are 230 kV or 115 kV. These lines are mainly overhead, but in large cities such as Toronto they are often placed underground.

Subtransmission lines

These are a further step in getting the power to the individual customers. They transmit power in smaller quantities from area-supply transformer stations to large customers and distributing stations in or near cities, towns and villages. The main voltage levels are 44 kV, 27.6 kV or 13.8 kV. Some lines are overhead and others are underground.

Distribution lines

These are the final stage in the distribution of power to individual customers. They usually are the wood or concrete pole lines routed along streets, concession roads, and back fence lines. In new residential subdivisions they are often placed underground. For distribution to groups of customers, the voltage level is usually 12.48 kV, 8.32 kV or 4.16 kV. For the final stage of distribution to the premises of individual customers, the voltage level is 120/240 volts for residential, 120/240 volts or 120/208 volts for small commercial customers or 600 volts for light industries.

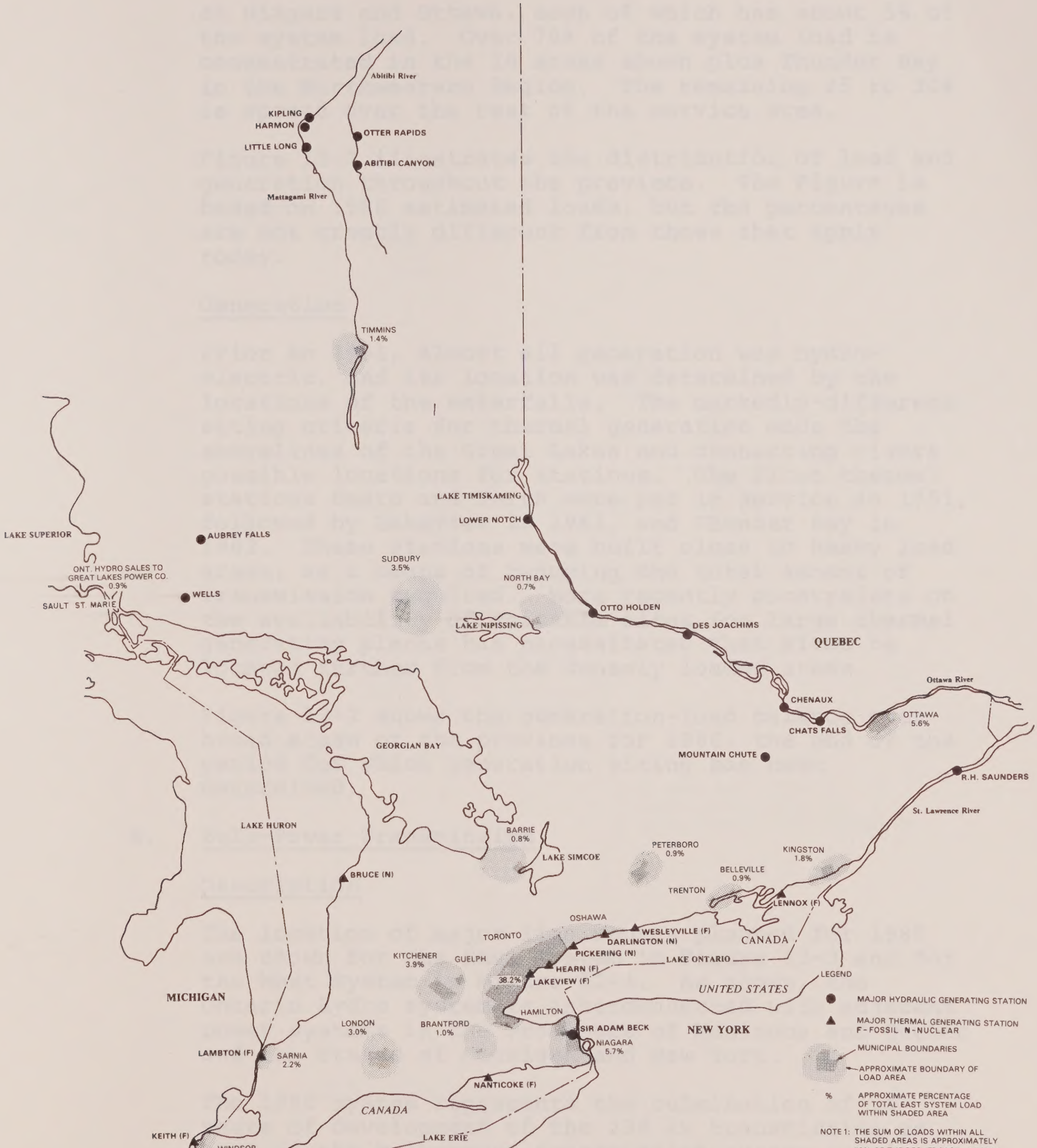
12.2 The Ontario Hydro Transmission System

A. Geographical Distribution of Load and Generation

The configuration of a transmission system depends on the magnitude and location of the loads and the generation.

Loads

Ontario Hydro supplies power to customers throughout almost all of southern Ontario, and much of northern Ontario, but the amount of power varies widely between the densely-loaded areas such as Toronto and the rural areas. Figure 12-1 shows the areas of greatest load concentration. Over 35% of the system load is concentrated in the Oshawa-Toronto-Hamilton area. Other concentrations are much smaller, such as



MAJOR LOAD CONCENTRATIONS & GENERATING STATION LOCATIONS IN ONTARIO

FIGURE 12-1

at Niagara and Ottawa, each of which has about 5% of the system load. Over 70% of the system load is concentrated in the 16 areas shown plus Thunder Bay in the Northwestern Region. The remaining 25 to 30% is spread over the rest of the service area.

Figure 12-2 illustrates the distribution of load and generation throughout the province. The Figure is based on 1986 estimated loads, but the percentages are not greatly different from those that apply today.

Generation

Prior to 1951, almost all generation was hydro-electric, and its location was determined by the locations of the waterfalls. The markedly-different siting criteria for thermal generation made the shorelines of the Great Lakes and connecting rivers possible locations for stations. The first thermal stations Hearn and Keith were put in service in 1951, followed by Lakeview in 1961, and Thunder Bay in 1962. These stations were built close to heavy load areas, as a means of reducing the total amount of transmission required. More recently constraints on the availability of suitable sites for large thermal generating plants has necessitated that sites be located farther from the densely loaded areas.

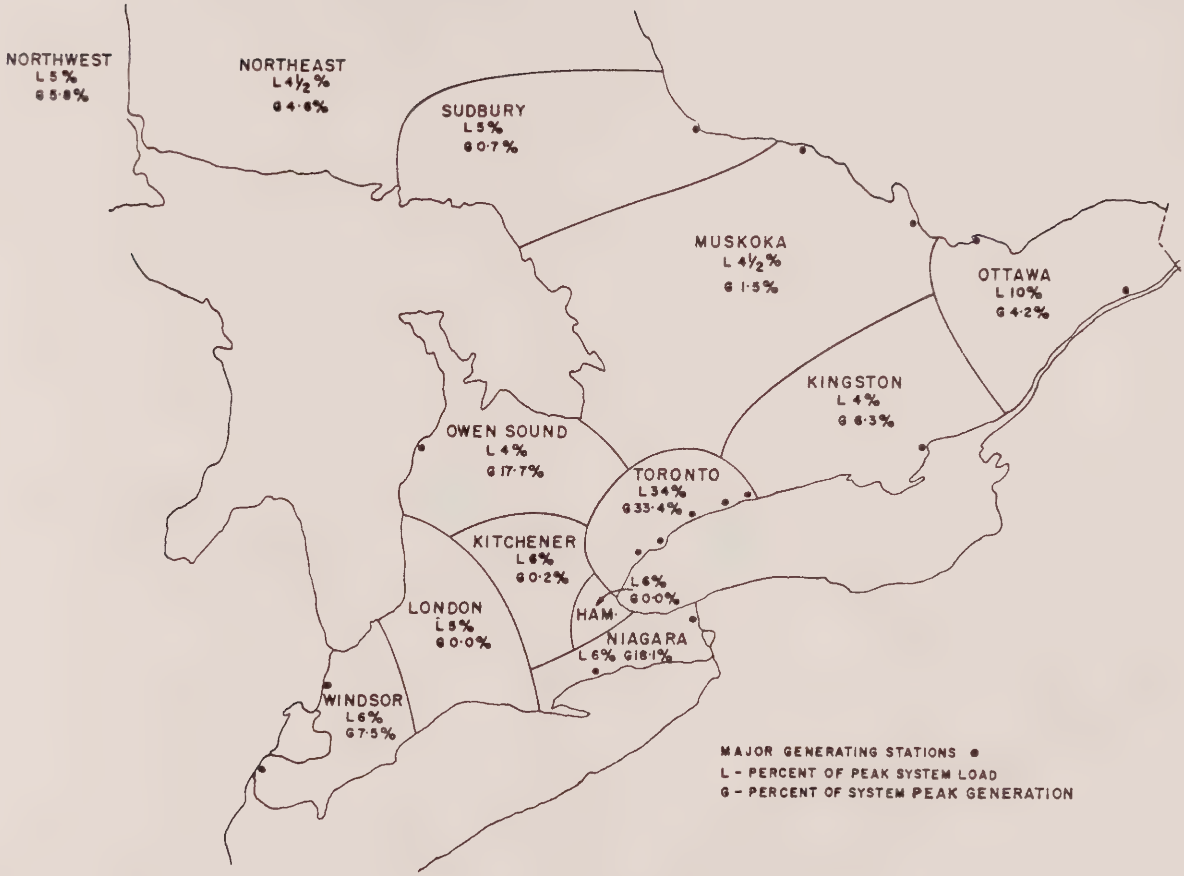
Figure 12-2 shows the generation-load balance over broad areas of the province for 1986, the end of the period for which generation siting has been determined.

B. Bulk-Power Transmission

Description

The location of major line routes planned for 1980 are shown for the East System in Figure 12-3 and for the West System in Figure 12-4. As shown, the Ontario Hydro system is interconnected with adjacent power systems in the Provinces of Manitoba and Quebec and the States of Michigan and New York.

The 1980 system represents the culmination of 50 years of development of the 230 kV transmission as part of the bulk-power transmission system and is an early stage in the development of 500 kV as the new bulk-power system voltage. The first bulk-power transmission system, starting about 1910, was a 115 kV system. In 1928, 230 kV was introduced and has been expanded as an overlay of the 115 kV system up

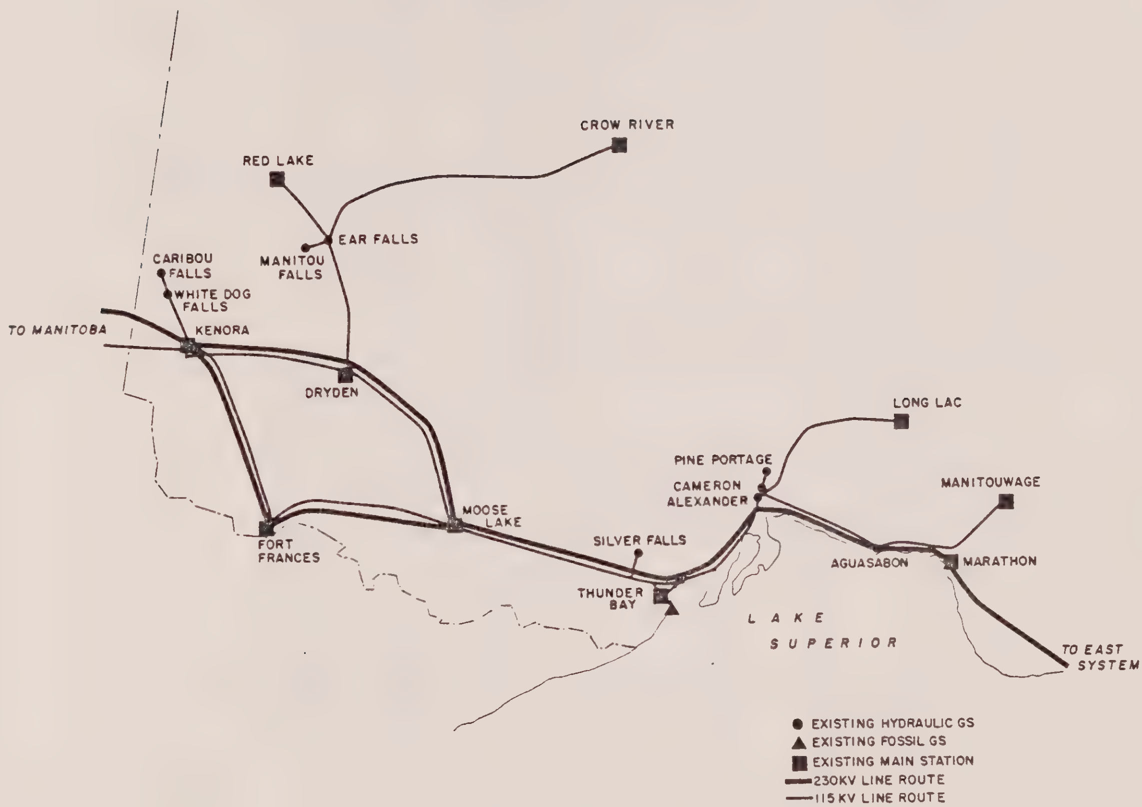


ONTARIO HYDRO
TOTAL SYSTEM
PERCENT OF LOAD AND GENERATION
BY AREAS - 1986

FIGURE 12-2

**ONTARIO HYDRO
EAST SYSTEM
MAJOR 500 kV AND 230 kV LINE
ROUTES AND STATIONS
1980**

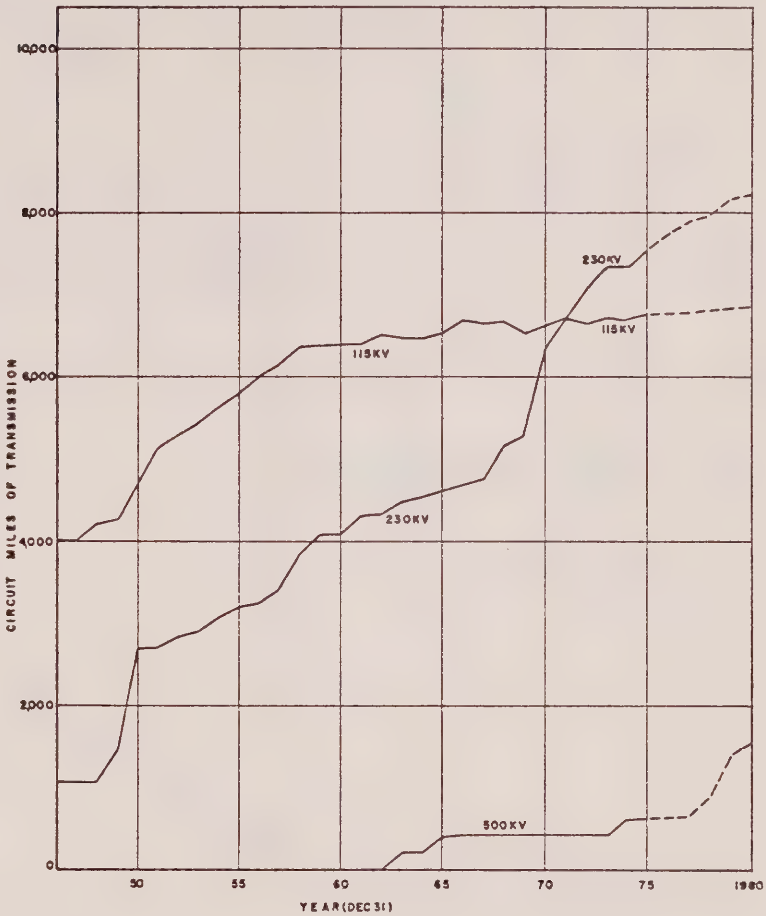
FIGURE 12-3



ONTARIO HYDRO
WEST SYSTEM
MAJOR 230KV AND 500KV
LINE ROUTES AND STATIONS

FIGURE 12-4

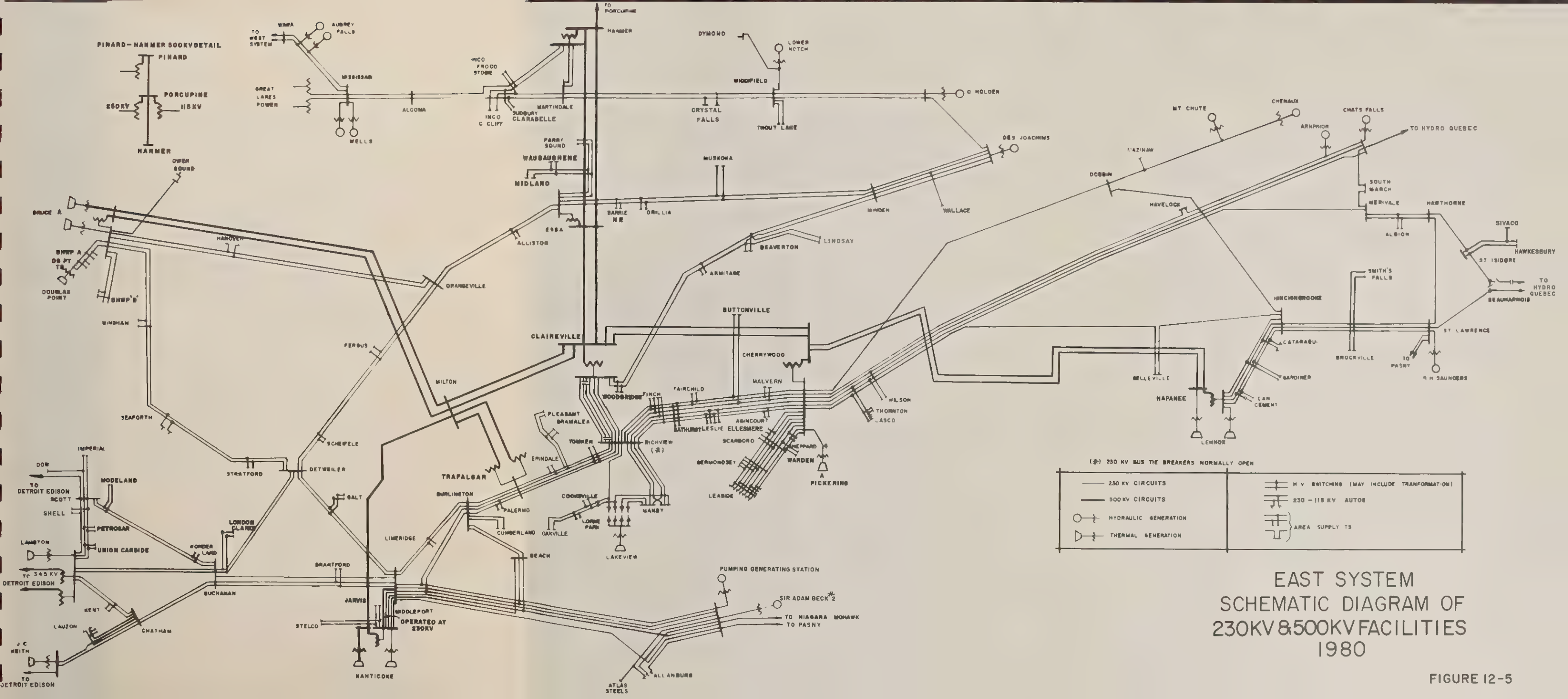
to the present time. In 1963, 500 kV was introduced and will increase rapidly in importance in the 1970's. The growth in the number of circuit miles of transmission in service since 1946 is shown below:



Single line diagrams for the 1980 transmission facilities in the East and West Systems are shown in Figures 12-5 and 12-6 respectively. These diagrams do not show the complete switching facilities necessary to connect the circuits into an integrated system. By way of illustration Figure 12-7 is the single-line diagram for Claireville Transformer Station planned for the Toronto area.

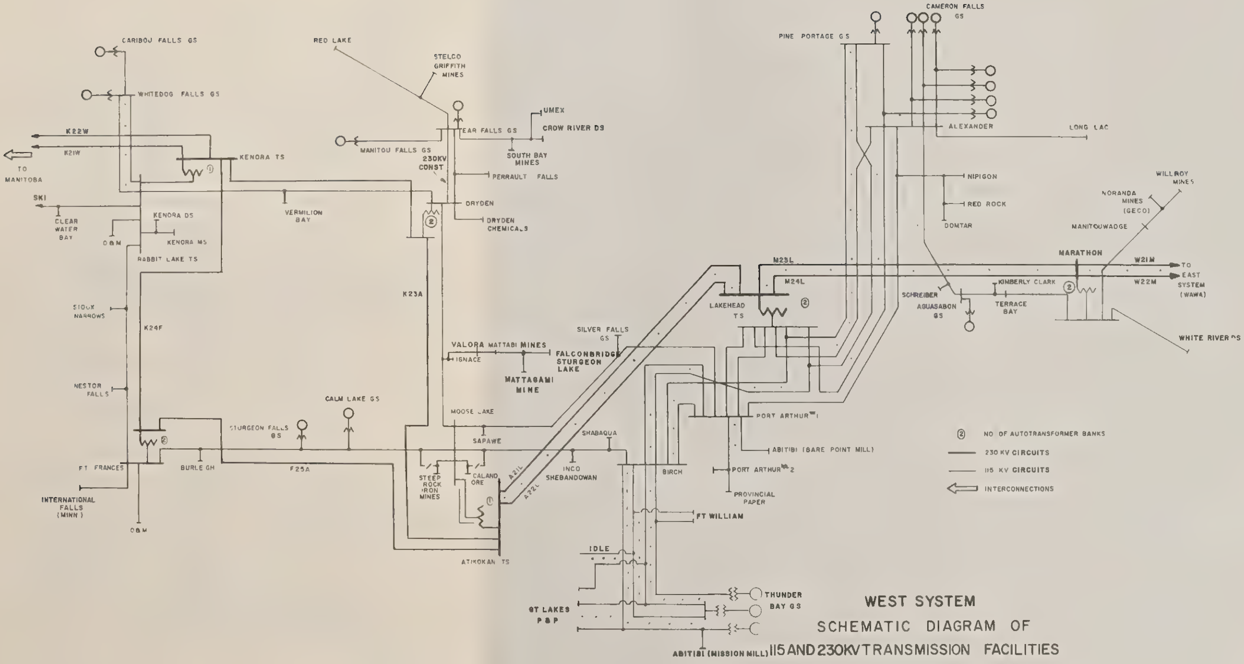
Integrated Transmission System

The Ontario Hydro transmission system permits load areas to be supplied from a number of generating



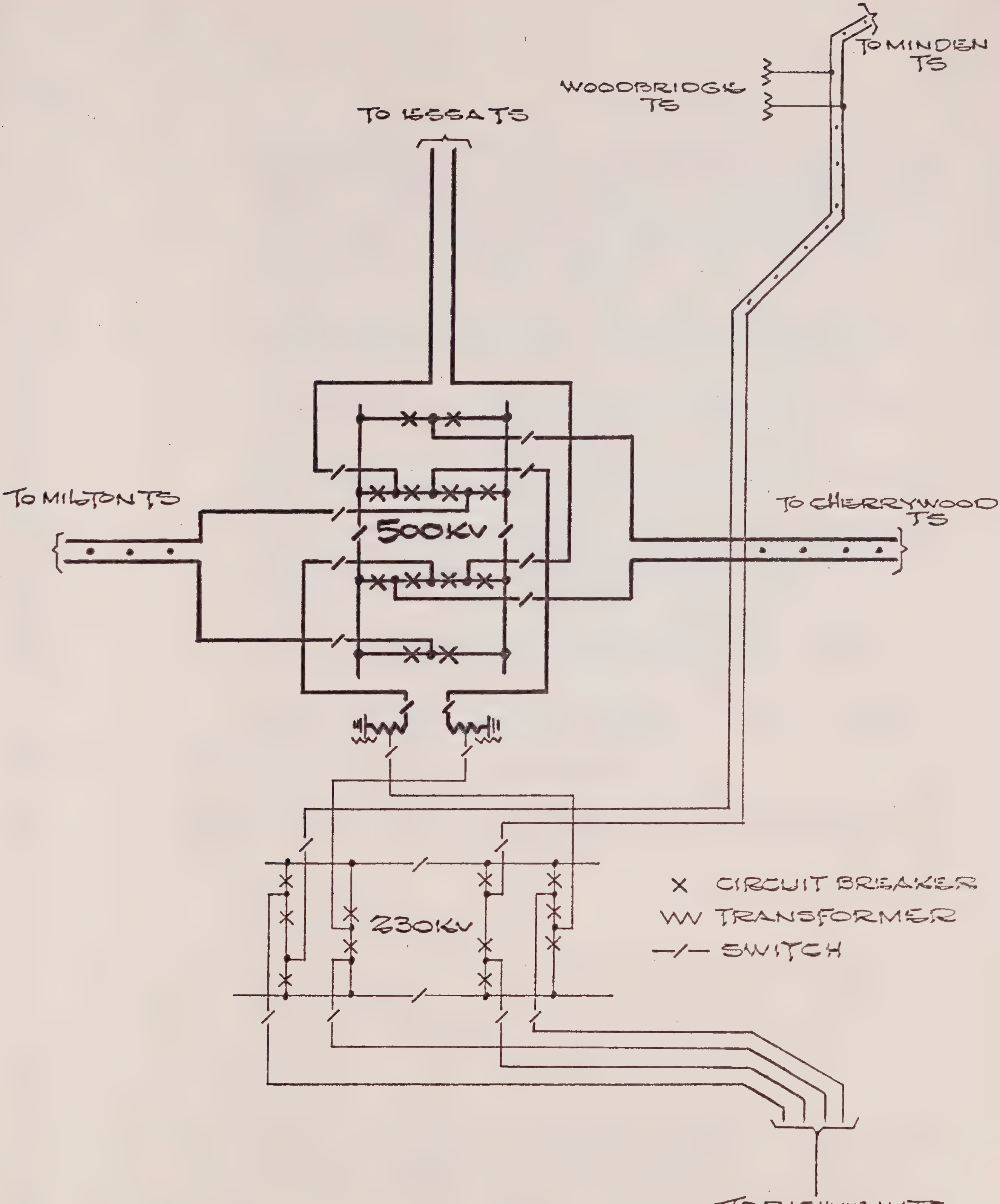
EAST SYSTEM
SCHEMATIC DIAGRAM OF
230KV & 500KV FACILITIES
1980

FIGURE 12-5



WEST SYSTEM
SCHEMATIC DIAGRAM OF
115 AND 230KV TRANSMISSION FACILITIES
1980

FIGURE 12-6



CLAIREVILLE TS
PLANNED 1978-80 FACILITIES

FIGURE 12-7

stations. This type of system is known as an integrated system, and is the type used by most large utilities throughout the world. It contrasts with a system in which groups of customers are each supplied from a separate isolated generating station. The isolated system is the type often used in remote areas, such as northern Canada.

Although the integrated power system requires more high-voltage transmission, it has been adopted for major systems because of the following advantages:

- Reduced generation reserve requirements for the same reliability of supply and unit sizes and types.
- Reduced operating costs because full use can be made of generation with the lowest production cost.
- Reduced capital expenditures from economies of scale (e.g. use of large generating units), more freedom in selecting the type of generation, and a more efficient generation construction program.
- Greater flexibility in locating generating station sites and in operating the generation.
- Ability to supply large fluctuating loads with small swings in voltage and frequency.

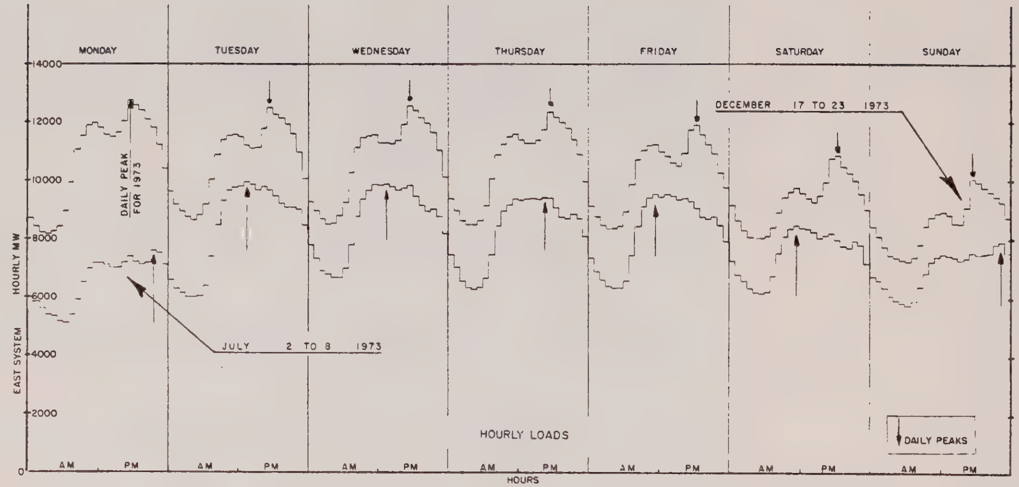
12.3 Transmission Loading - Requirements

The electric loading on a transmission circuit varies from moment to moment in a complicated manner. Variations occur in:

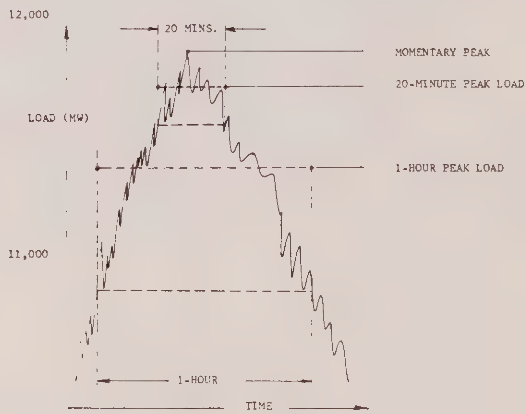
- Load demand
- Generation in operation
- Power transfers over interconnections with adjacent power systems
- Outages of individual circuits or other elements.

Loads

The power used by an individual customer varies from instant to instant. The aggregate power used by all customers together (called the system distributed load) also varies from instant to instant, but follows a fairly predictable pattern. The patterns plotted in terms of average loads during a clock hour for a week in July and December 1973 are shown on page 12.0-6.



Within the hour, the load varies from instant to instant, and its pattern over a peak hour is more accurately pictured below:



An idea of the extent of the variation over the week can be gained from observing that in winter the Sunday morning low is only about 56% of the weekday peak. The pattern changes from winter to summer, due in part to changes in the requirements for heating and lighting.

The peak load in a calendar year usually occurs in December. The amount of this load has increased in almost every year since Ontario Hydro started operating. The growth can vary considerably from

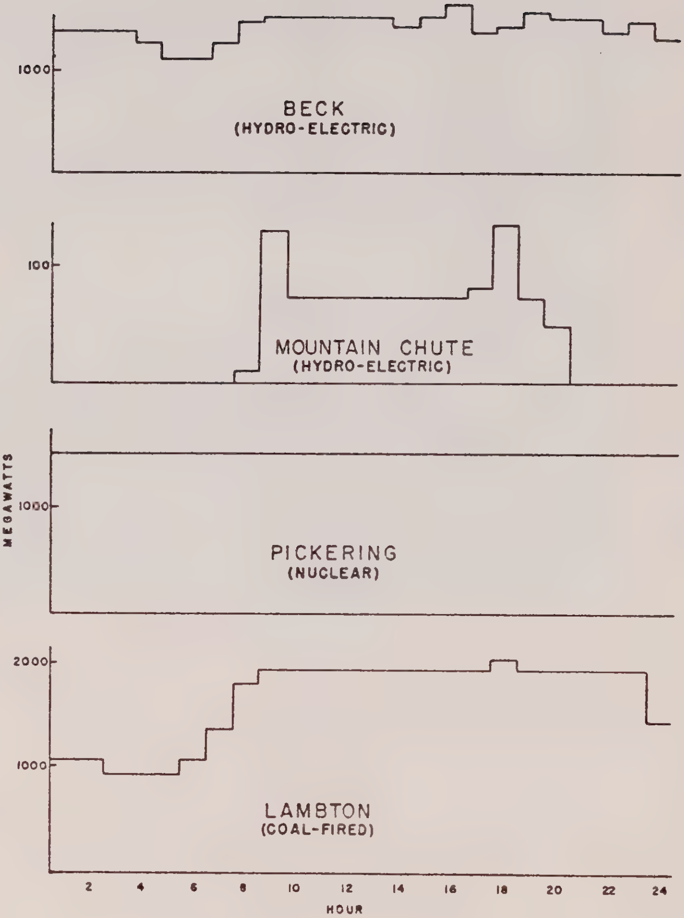
year to year because it is affected by short term weather and economic effects, but if these effects are averaged out over a few years, the long term growth over the past 50 years has been at a rate of just below 7% per year compounded yearly.

All of these load patterns are of interest in transmission planning since each of them must be considered to arrive at the most critical loading on the transmission circuits and to evaluate transmission losses.

Generation Schedules

The generation schedule can also affect transmission line loadings. This schedule is determined by a number of factors which are discussed in more detail in the Memorandum on Generation Planning Processes. Major factors are generation production costs, fuel availability and environmental considerations.

The outputs of four generating plants, 2 hydro-electric, 1 nuclear and 1 coal fired, for December 18, 1975 is shown on page 12.0-8.



Interconnections

Interconnections with other utilities can change loadings on transmission elements in the system from:

- sale or purchase of power which changes the operating pattern of Ontario Hydro generation and the transmission loading.

- circulating power

"Circulating power" comes about because Ontario Hydro's transmission system is connected electrically, through a number of interconnection circuits at several locations, to a large

transmission system in the United States. These interconnection circuits form many parallel paths between the two systems. Thus, even though the total power at any instant being transferred between Ontario and United States may be zero, the transfer across any interconnection circuit will probably not be zero. As a typical example, 300 MW may be flowing from Ontario to Michigan through four interconnections in the Sarnia-Windsor area, and at the same time 300 MW will be flowing from New York to Ontario through the interconnections at Niagara and Cornwall. At another time the flow may be 200 MW, but in the reverse direction. The change in flow will affect the loading on many circuits in Ontario.

Transmission Outages

Transmission elements may be out of service for maintenance or repair or to provide safe clearances for work on adjacent elements. With transmission elements out of service, the loading on the remaining elements is increased.

Since the useful life of a transmission line is usually in the order of 50 years, the transmission planner is interested in estimating the transmission line loading as far into the future as practical. Where the line is used to incorporate generation radially into the main network or to supply a load connected radially from the network, the transmission line loading can be determined from a knowledge of the generation schedule or the estimated load. Where the line forms part of the interconnected network the problem is more complex.

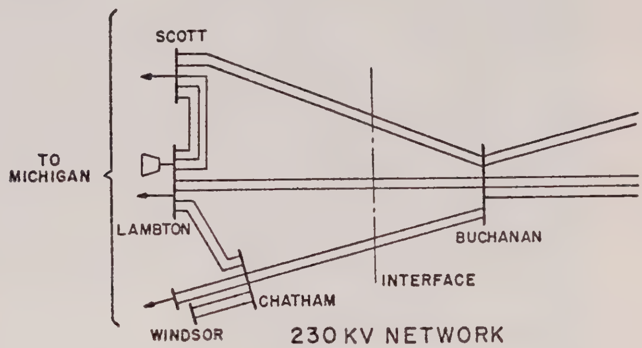
A technique commonly used in estimating the possible loading on a link in the network, is to draw an imaginary line cutting the system into two parts. The loading across this line or interface between the two parts of the system can then be determined by examining the load and generation on each side of the line. Interface loadings can be approximated by simple calculations for a wide range of system conditions such as:

- The maximum generation and coincident minimum load in each part of the system.

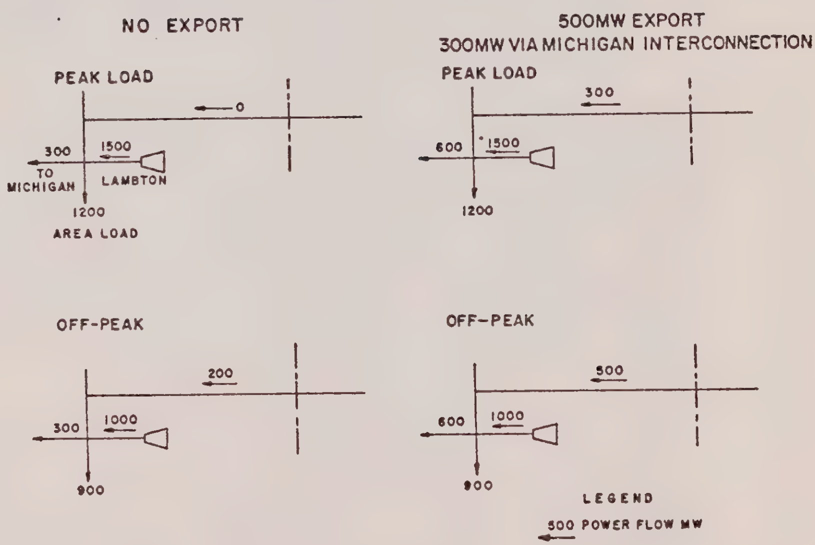
- Economic loading of the generation for a range of load conditions.

- Loadings which can occur with generation on forced outages.

An example of the use of this technique on an interface west of Buchanan TS (London) is shown below:



230 KV NETWORK



INTERFACE FLOWS

A more accurate estimation of interface loadings and the loadings on individual circuits crossing the interface is determined on the computer by load flow analysis as explained in Section 12.14.

12.4 Transmission Loading - Capability

The amount of power a transmission circuit can carry depends on the characteristics of the other elements in

the system to which it is connected as well as the characteristics of the circuit itself. Since the system external to the circuit is continually changing with changes in load, generation and transmission, the circuit capability is also changing.

The principal considerations which determine transmission circuit capability are:

- voltage levels

- losses

- thermal limits

- stability

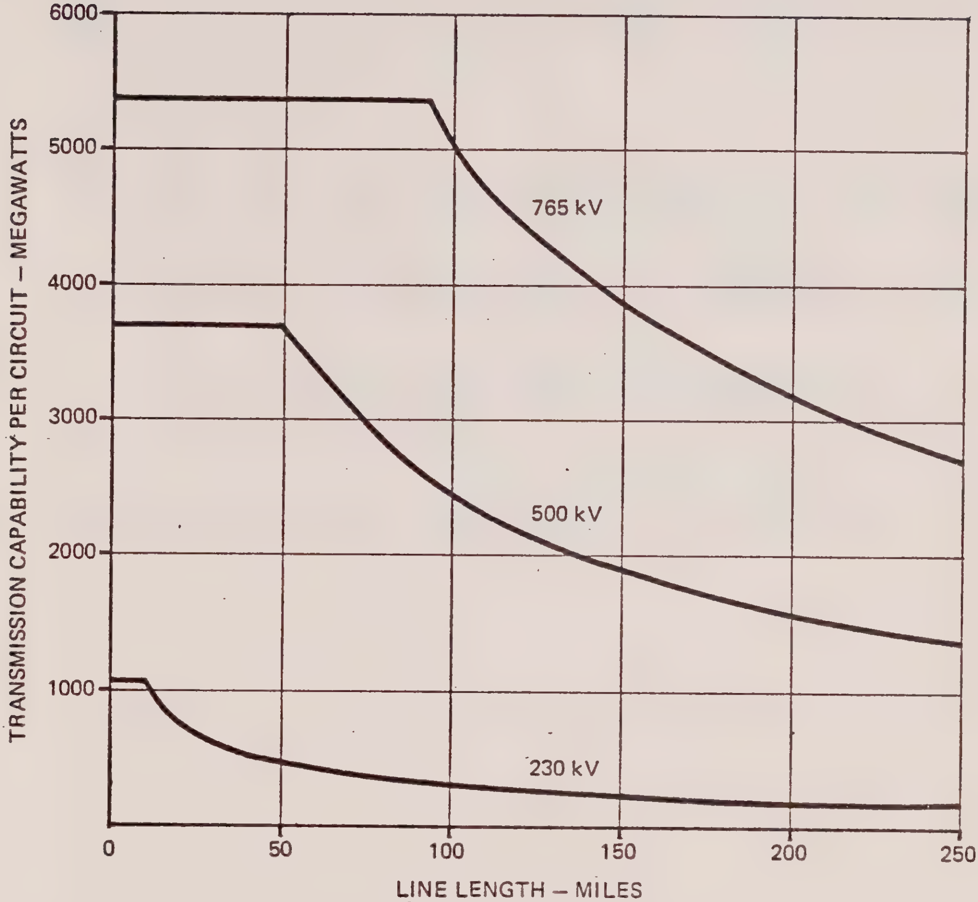
- protective relay characteristics

Each of these considerations are discussed in more detail in subsequent sections.

Despite the limitations in providing general loading capabilities for circuits, some generalizations are necessary to permit broad comparisons among circuits of different voltage levels and lengths.

The "characteristic impedance loading" (sometimes called surge impedance loading) is a term used to provide a rough indication of the load that can be carried by long transmission circuits. The characteristic impedance loading is a function of the physical arrangement of the transmission circuit conductors, and is nearly constant for circuits of a given voltage level. It is about 140 MW for a 230 kV circuit, about 960 MW for a 500 kV circuit and about 2250 MW for a 765 kV circuit. Circuits up to several hundred miles long usually have loading capability greater than the characteristic impedance loading.

Figure 12-8 shows the approximate transmission capability of 765 kV, 500 kV and 230 kV circuits versus length. For the short lengths the values are based on a current limit of 2500 amperes for 230 kV and 4000 amperes for 500 and 765 kV. These are the ampacity limits of station equipment such as switches, breakers, current transformers, etc., which are available from most major manufacturers. For the longer lengths the limits are based on stability and voltage considerations. The Figure shows that for lengths of 250 miles the power transmitting capability of a 500 kV circuit is about 7-1/2 times that of a 230 kV circuit and about 1/2 that of a 765 kV circuit. For short lengths, the power transmitting capability of a 500 kV circuit is about 3-1/2 times that



POWER TRANSMISSION CAPABILITY
VS
DISTANCE

Line Number

of a 230 kV circuit and about 2/3 that of a 765 kV circuit.

This Figure shows loading capabilities for individual circuits. Reliability criteria require provision to be made for elements out of service. Therefore it should be noted that the capability of elements operating in parallel is less than the sum of the capabilities of the individual elements.

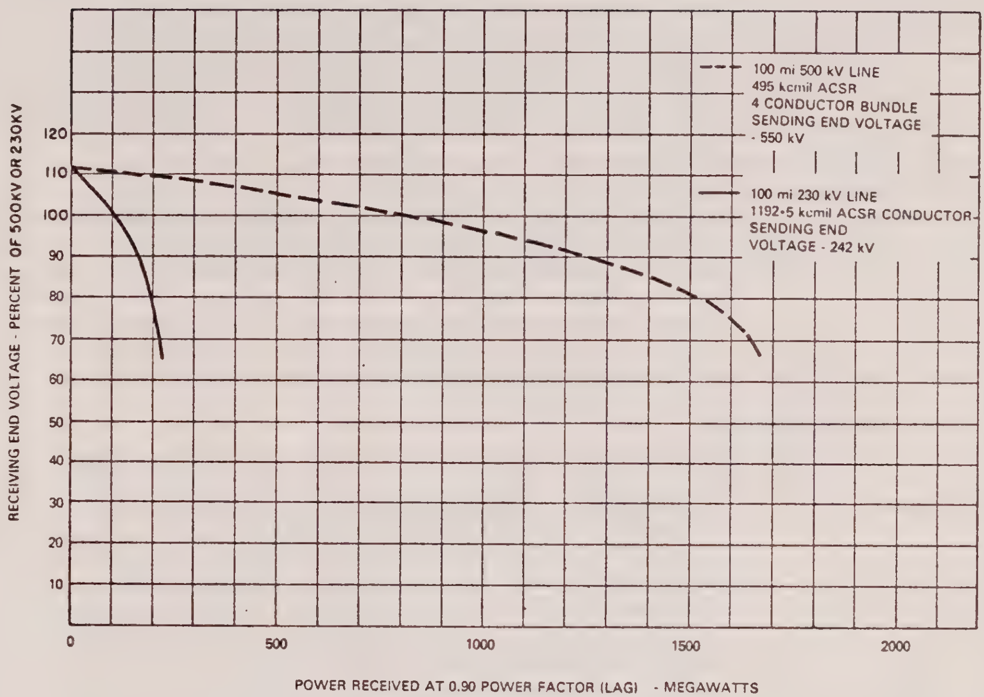
12.5 Voltage Levels

Voltage levels on the bulk power transmission system must be maintained within fairly close limits for two reasons:

- Operation close to the maximum permissible voltage tends to minimize losses and provide the highest security.

- Only a limited variation is permissible if satisfactory voltage is to be provided at the customer location.

Voltage levels tend to drop as loading increases as shown on page 12.0-13 for a 500 kV and 230 kV circuit.



Voltage control is necessary to keep voltage levels within acceptable limits. This voltage control is provided by two principal means:

- changing transformer taps which change transformer ratio.

- supplying or absorbing reactive power.

Each of these means of voltage control is discussed in turn.

A. <u>Transformer Taps</u>

Two types of transformer taps are provided: off-load in which the transformer must be removed from service to change the tap, and on-load (LTC) which can be changed with the transformer carrying load.

It is Ontario Hydro's general practice to provide LTC on area supply transformers stepping down from 230 kV or 115 kV to 44 kV, 27.6 kV or 13.8 kV. The tap ranges on these transformers are normally $\pm$ 10% to

15% of nominal voltage if off-load taps are provided and larger ranges if no off-load taps are provided. In order to keep voltages at loads near the end of the subtransmission lines at acceptable levels, it is normal to have the voltage on the station low-voltage bus about 5 percent higher at peak load than at light load.

Most of the tap-changer range is required to take care of conditions such as circuits or transformers out of service, but about a 5% daily variation is permissible on the 230 kV system while still keeping within the design criteria for low-voltage buses. Longer term variations in voltage can be taken care of by changing off-load taps on the area supply transformers.

Two types of 500/230 kV autotransformers are being purchased. One type of transformer has no LTC equipment so that the ratio of the 500 kV voltage to the 230 kV voltage must remain relatively fixed for daily periods but can be varied over a longer period by changing off-load taps. This type of transformer will be used in the Toronto Hamilton area where it will be possible to maintain a relatively constant 500 kV voltage over long periods of time. The second type of 500/230 kV autotransformer has $\pm$ 10% LTC equipment which will permit maintaining the 230 kV voltage relatively constant while the 500 kV voltage varies over a significant range.

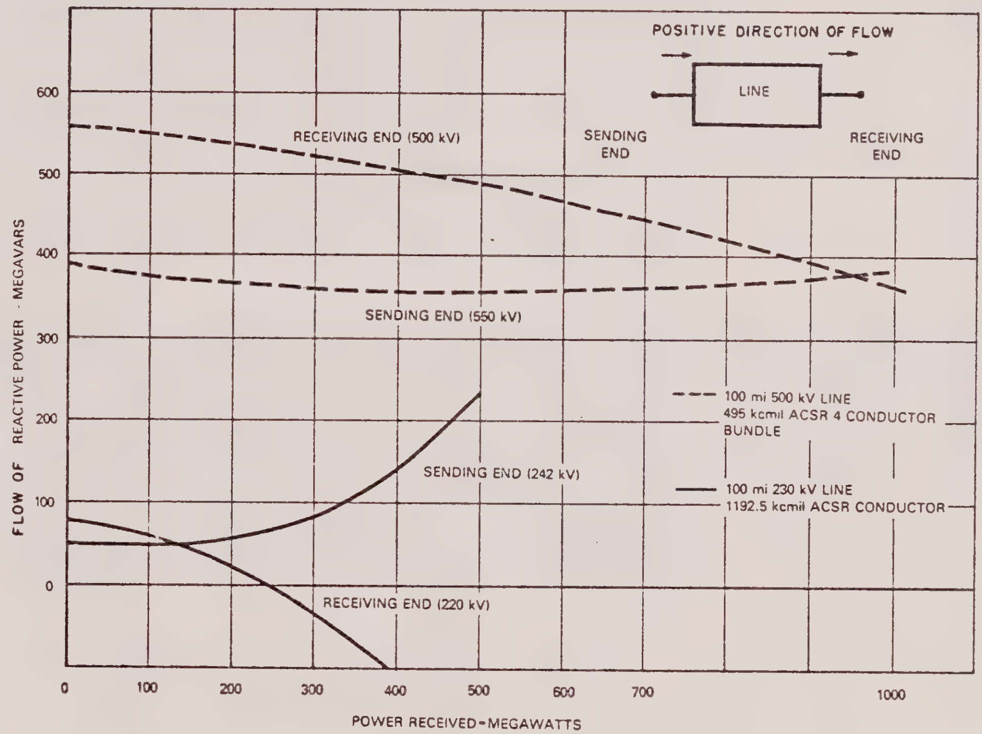
Off-load transformer taps are provided at most generating stations and provide another means of controlling the voltage level on the high voltage system.

B. Reactive Power

Reactive power occurs in all ac circuits which have reactance or capacitance. Unlike real power, commonly referred to as power, it cannot be used to perform work and its production, except for additional losses it may create, does not consume energy in the form of fuel or falling water. It is however similar to power in that it is required for the functioning of many types of electric equipment such as induction motors and rectifiers. Reactive power is produced or absorbed by synchronous machines such as generators, synchronous motors and synchronous condensers. It is produced by capacitors, lightly loaded transmission lines and cables. It is absorbed by reactors, transformers and heavily loaded transmission lines. Control of

reactive power is an important consideration in designing and operating the power system because an appropriate balance must be obtained between the reactive power produced and absorbed in order to maintain satisfactory voltage levels.

As noted a transmission line can either produce or absorb reactive power depending upon the power it is delivering. The figure below shows how reactive power varies with power delivered for 100 mile long, 230 kV and 500 kV transmission circuits.



With zero power on the circuit, the 230 kV circuit delivers about 80 Megavars (MVAR) at the receiving end and absorbs 60 MVAR at the sending end. The sending and receiving end reactive power are equal at about 140 MW, the characteristic impedance loading. At 300 MW, the circuit absorbs over 100 MVAR between the receiving and sending ends. These reactive power requirements assume that the sending and receiving end voltages remain constant at 242 kV and 220 kV

respectively. If the reactive power shown cannot be absorbed or produced by the receiving and sending ends, these voltages cannot be maintained.

At 500 kV, with zero power on the circuit the reactive power delivered at the receiving end is 550 MVAR and the reactive power absorbed at the sending end is 390 MVAR. The sending and receiving end reactive power are equal at about 960 MW, the characteristic impedance loading for a 500 kV circuit.

Generators or synchronous condensers are provided with automatic voltage regulators which maintain the machine terminal voltage constant during variations in load on the system. Within limits the operator can adjust the voltage regulator to vary the reactive power output to obtain the desired voltage levels.

Synchronous condensers are synchronous machines which are installed for the purpose of controlling voltage by producing or absorbing reactive power. Ontario Hydro has about 670 MVAR of synchronous condensers installed at load centres in sizes up to 60 MVAR.

Static capacitors are also used as reactive sources. They are provided in banks of up to 30 MVAR for voltages from 13.8 kV to 44 kV and in banks of up to 100 MVAR at 115 kV and 200 MVAR at 230 kV. Most banks are provided with switching devices so they can be connected or disconnected as required by system conditions. The growth in static capacitor installations on the system up to December 1975 is shown in Figure 12-9. A further 1600 MVAR of capacitors are expected to be required by the end of 1977.

The major advantages of static capacitors as compared to synchronous condensers are:

- Lower initial cost

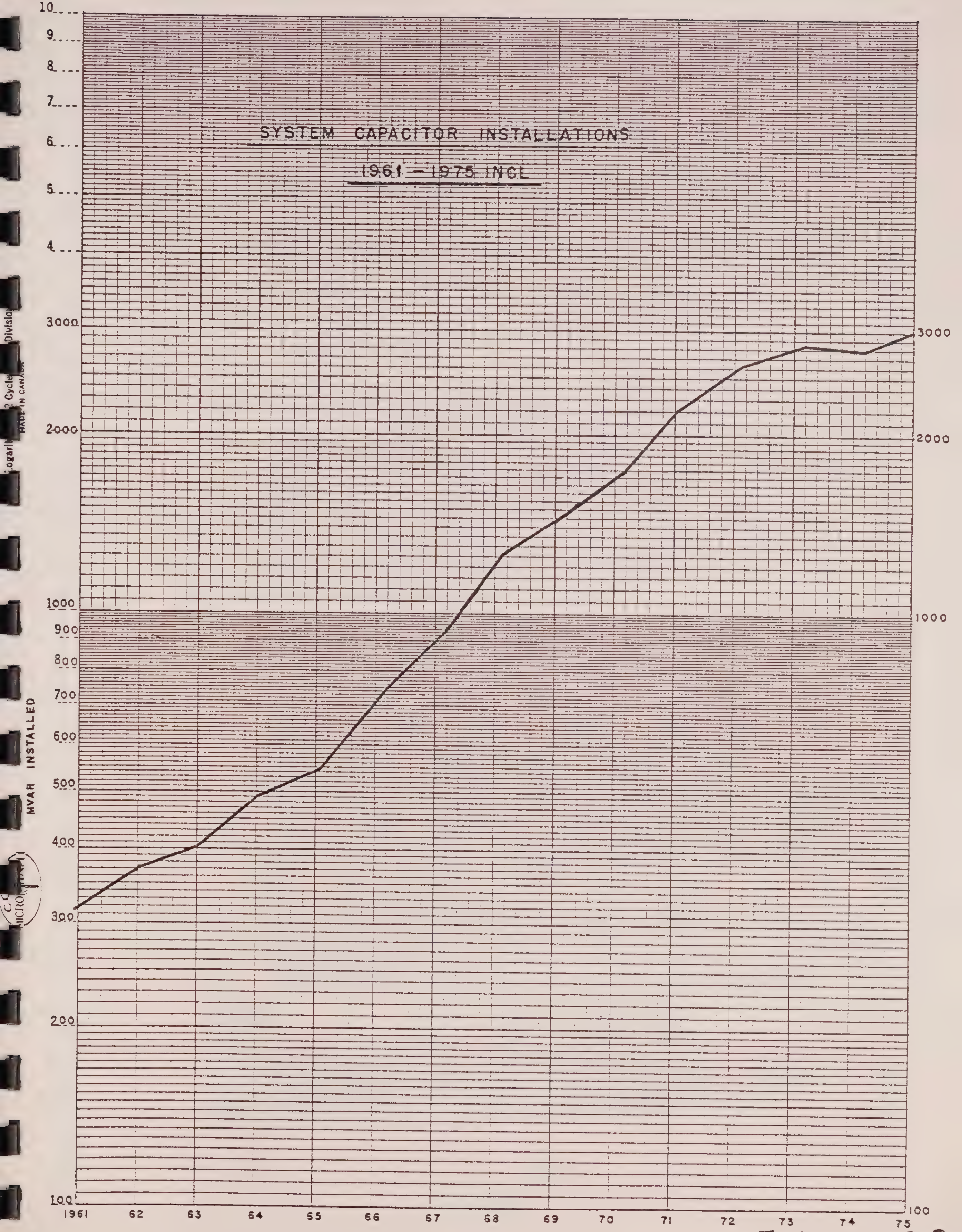
- Lower losses and less maintenance

- Readily installed in a wide range of sizes

- No increase in the magnitude of short circuit currents

Their major disadvantages as compared to synchronous condensers are:

- In general, do not contribute to system stability.



SYSTEM CAPACITOR INSTALLATIONS
1961 — 1975 INCL
MVAR INSTALLED
1961
62
63
64
65
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71
72
73
74
75
100
200
300
400
500
600
700
800
900
1000
2000
3000

FIGURE 12-9

- Control is in discrete steps rather than continuous.
- They may aggravate voltage changes caused by fluctuating loads.
- Switching them can cause excessive overvoltages on the system and on station control circuit wiring.
- Can cause undesirable resonance conditions.

The latter two disadvantages can be eliminated by careful design.

Shunt reactors, which are similar to transformers but have a single winding on an iron core with air gaps, are used to absorb reactive power. Sizes in use by Ontario Hydro range from 15 MVAR to 150 MVAR in voltages from 13.8 kV to 500 kV. The lower voltage reactors have been provided with switching devices so they can be disconnected as required by system conditions. The 500 kV reactors are connected to 500 kV circuits through off-load switches and are switched on and off with the circuit. About 1300 MVAR of reactors are in service.

In recent years, controllable static compensators have been developed which use thyristors to control the reactive power absorbed by the reactor by saturating the iron core of the reactor. These devices are normally operated in parallel with a capacitor bank so that they have a steady-state characteristic which is similar to that of a synchronous condenser ie - reactive power can be produced or absorbed and is continuously and rapidly controllable. These devices have not been widely used to date and are not in use on Ontario Hydro's system. They are static devices and have lower losses and require less maintenance than synchronous condensers.

Another method sometimes used to control voltage is to switch lines out of service at light load periods, thereby reducing reactive power produced. This has the disadvantage that it reduces system security.

12.6 Losses

By comparing the peak or energy delivered to the low voltage buses of Ontario Hydro's area supply stations and the high voltage customers' stations to that delivered from the generating stations, the losses can be determined.

Such comparisons have indicated that the average energy loss over a year is about 5%.

While electric losses occur in all transmission system elements, the principal losses occur in the transmission circuits and transformers. Losses in each of these elements are considered in the following.

A. Transmission Circuits

Even when carrying no real power there are some transmission circuit losses due to the flow of reactive power. However for overhead lines these are relatively small. For example the no load losses in a 500 kV, 100 mile circuit under fair weather conditions are about 0.07 MW.

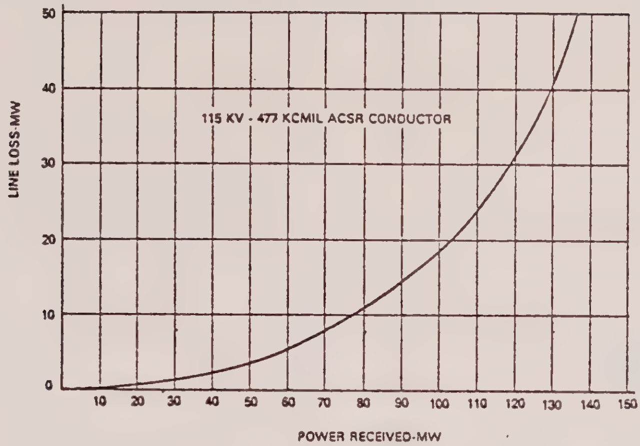
The losses in a transmission circuit vary approximately as the square of the power carried. Typical losses for 115 kV, 230 kV and 500 kV circuits 100 miles in length are shown in Figure 12-10. At the usual design loadings for normal operating conditions, circuit losses for a 100 mile line are about 2 to 3% of the load carried. Under heavy emergency loadings, the losses could be considerably higher.

The system designer has some control over circuit losses firstly by choosing the appropriate voltage level and secondly by choosing the conductor size. The choice of a conductor size is based on both the initial cost of the line and the long term operating and capital costs.

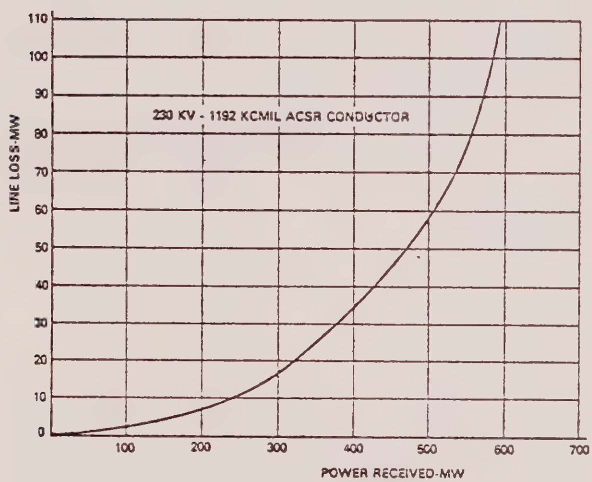
At extra high voltage levels corona losses can be a factor in selecting conductor size or arrangement. Corona losses increase with line operating voltage and are relatively independent of line current. Corona losses for the usual line design are very small under fair weather conditions but can increase rapidly under foul weather conditions eg. fog, rain or snow. For the weather conditions prevailing in Ontario, the value of losses due to corona is not high enough to affect the 500 kV line design.

B. Transformers

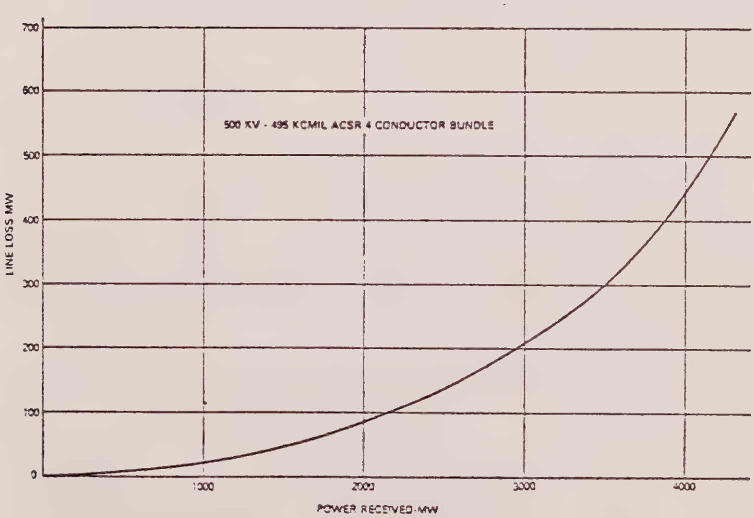
At full load, the transformer is a very efficient device, with typical full load efficiency being about 99.5%. A typical curve of transformer losses as a percent of rated load is shown on page 12.0-19.



115 KV



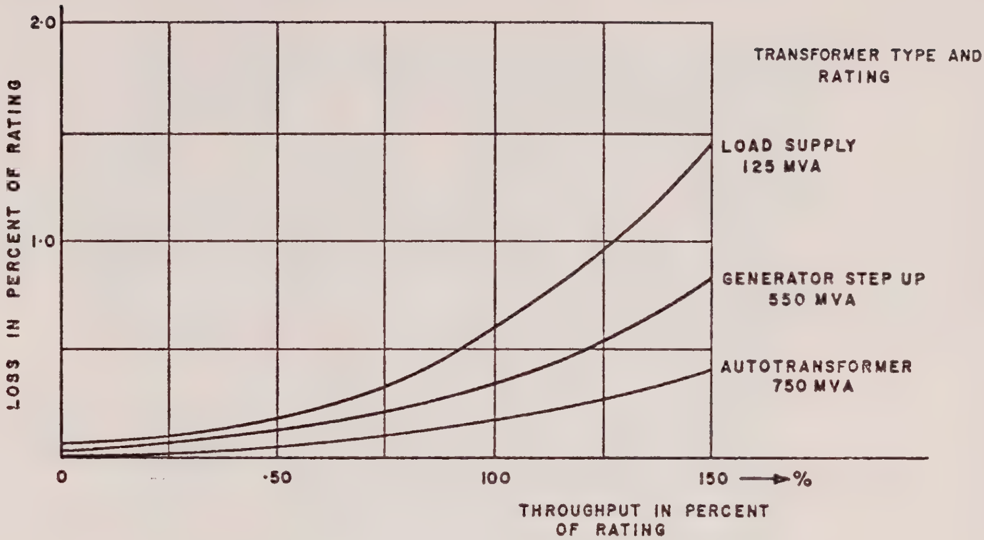
230 KV



500 KV

TRANSMISSION LOSSES FOR 100 MILE CIRCUIT
(WITH FIXED TRANSMITTING AND RECEIVING VOLTAGES)

FIGURE 12-10



The transformer designer has some control over transformer losses but to reduce losses requires a larger more costly transformer. Ontario Hydro influences transformer losses by specifying to the transformer manufacturer the value that is assigned to a kilowatt of no-load loss and a kilowatt of load loss.

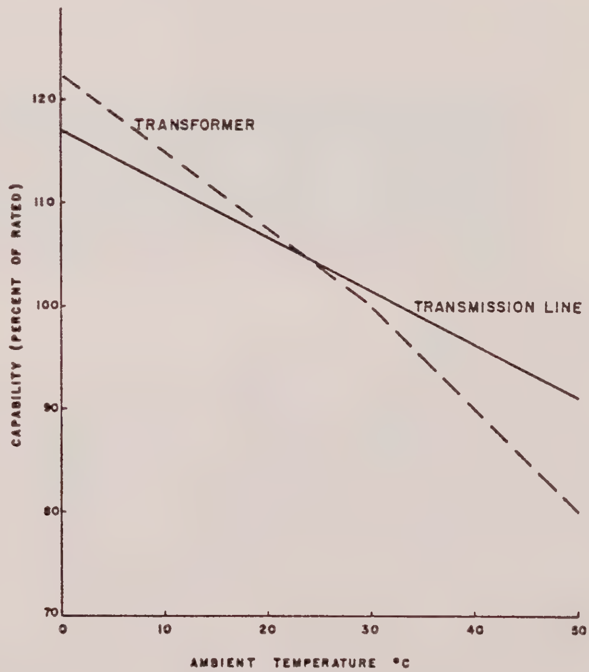
12.7 Thermal Limits

A limit on the load which can be carried by a transmission circuit or other item of equipment is generally set by the maximum temperature at which the equipment can be safely operated. All equipment is subject to losses which increase rapidly as the load increases and which are manifested by the production of heat within the equipment, and an increase in its temperature above ambient. The limit is generally set because operation at elevated temperatures will cause deterioration over time in the materials of which the equipment is made. For example, high temperatures cause gradual annealing and loss of strength of the aluminum conductor of a transmission line. High temperatures cause deterioration of the paper and oil in a transformer. The capability limit is set by the maximum temperature at which the equipment should be allowed to operate, taking into account the effect of

temperature on rate of deterioration. These temperatures are chosen so that the lifetime of the equipment will be in the range of about 20 to 50 years.

In the case of transmission lines, there is a second temperature-related effect which sometimes takes precedence over annealing in setting the maximum permissible operating temperature. This is the increased sag and decreased clearance to ground which occurs as the conductor temperature rises. Depending on the initial design of the line and its subsequent operating history, there is a maximum permissible temperature which results in a minimum permissible clearance to ground for safety to the public.

Thus, equipment operating temperature sets a limit on the loading capability, and this capability varies according to the ambient weather conditions in which the equipment is operating. Variations in ambient air temperature, wind, and solar radiation cause variations in the amount of heat that can be dissipated, and hence in the amount of load that may be carried. The relation between ambient temperature and capability is shown below.

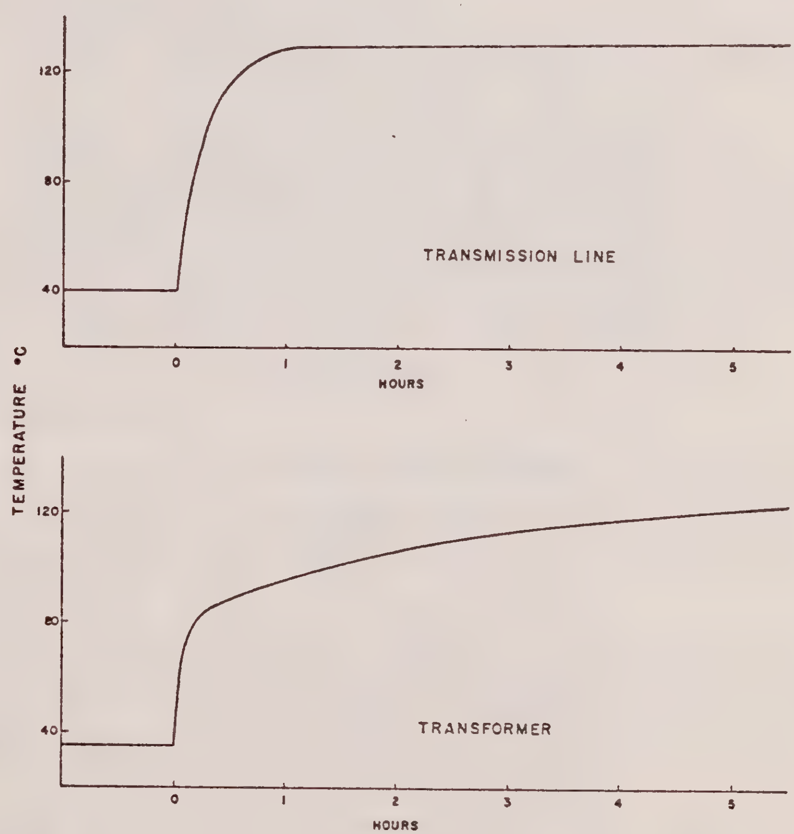


The limits of temperature define the limit of day-in-day-out loading which will result in sufficiently slow deterioration that an adequate life is achieved. In

emergencies, short-term exposure to higher loads can be rationalized on two grounds.

1. High emergency loads cause more rapid deterioration, but if the loads are infrequent and of short duration, the overall effect in shortening life is small and is an economically-acceptable risk.

2. Because of the thermal lag in the equipment, it takes time for the effect of a higher loading to become evident as a higher temperature (referred to as a thermal time constant). Therefore high loads of very short duration do not cause much temperature rise or loss of useful life. The rate of increase in temperature for a sudden doubling of load is shown below.



Three thermal ratings which are commonly used in transmission planning are:

Normal Rating: This is the permissible continuous load of the facility for standard ambient conditions assuming a specified 24 hour load cycle and normal life expectancy.

Long Time Emergency Rating: (LTE)

This is the permissible loading of the facility for a 24 hour period assuming a specified preloading and reduced life expectancy.

Short Time Emergency Rating: (STE)

This is the permissible loading for 15 minutes taking full advantage of thermal lag, and assuming reduced life expectancy.

While the thermal rating of the transmission line conductors and many components of the station such as transformers, circuit breakers, switches, buswork, current transformers, relays, meters, wave traps must all be considered in determining the rating of a transmission line or transformer station, the system is normally designed so that one or other of the major high cost elements, the transmission line conductors or the power transformers is the limiting element.

The thermal characteristics of transmission circuits and transformers will be discussed briefly.

A. Transmission Circuits

Most power conductors installed on Ontario Hydro's high voltage lines are aluminum cable, steel reinforced (ACSR). As already noted, these conductors have a maximum design temperature which is based on either annealing or design sag temperatures. The annealing temperature is the conductor temperature above which the loss of strength of the aluminum becomes serious. In the past this has been taken as $200^{\circ}F$ ($93^{\circ}C$) for normal operation and $260^{\circ}F$ ($127^{\circ}C$) for emergency operation on the basis that not more than 10% of conductor strength will be lost in 50 years. A recent innovation being considered for the uprating of existing lines is to permit complete annealing of the aluminum conductor and rely on the strength of the steel core alone. If this proves to be successful, annealing will not be a limiting factor on many circuits. The limit will then be the design sag temperature, which is the maximum

temperature at which the circuit can be operated while maintaining standard clearances to ground and underlying facilties.

The actual temperature attained by a conductor is dependent on weather conditions prevailing at this time. Standard design weather conditions are:

Summer - 90°F (32°C), 1½ mph effective wind, bright sun

Winter - 50°F (10°C), 1½ mph effective wind, bright sun

With these assumptions it is estimated the ambient conditions will not exceed design conditions more than 3 to 5% of the time. Thus the circuit will be able to operate at or above its design capability for 95 to 97% of the time.

In operating the circuit, use is made of nomograms from which the operator can determine the permissible current for the ambient weather conditions.

Since the thermal time constant of transmission line conductor is relatively short, typically 10-20 minutes, Ontario Hydro does not normally distinguish between LTE and STE ratings and typically would base both these ratings on a conductor temperature of 260°F. Normal ratings would typically be based on a conductor temperature of 200°F. If annealing is not a problem, ratings based on higher temperature operation could be used.

B. Transformers

Power transformers are cooled by oil which circulates through the core and windings of the transformer. It absorbs the heat produced, and is then circulated through radiators where the heat is transferred to the ambient atmosphere.

The standard nameplate rating of a transformer is that load which it can carry continuously with normal life expectancy when the ambient temperature averages 30°C over a 24 hour period, and the hottest spot temperature of the copper windings averages 110°C.

Since most transformers are loaded with varying loads, and since the average ambient temperature rarely exeeds 30°C in Ontario, considerable advantage is taken of the varying nature of the load and lower ambient temperatures to permit loading transformers above their nameplate rating on a day-in-day-out basis without loss of life expectancy. In addition

to this, higher loads are permitted in emergencies with moderate loss of life expectancy by allowing the calculated hottest spot copper temperature to rise as follows:

Long term emergency - 140°C

Short term emergency - 180°C

Short term emergency loadings as high as twice the nameplate loading are permitted when advantage is taken of reduced ambient temperature, elevated hot spot temperature, and thermal lag in the equipment. The transformer takes 6 hours or so to reach steady temperatures. However, operating at these elevated temperatures causes rapid aging, and the total hours of operation at elevated temperatures must be carefully monitored if reasonable life expectancy is to be achieved. In addition, care must be taken to ensure that other parts of the transformer, such as bushings and tap-changers and associated equipment, such as disconnect switches and current transformers are adequate for the high emergency loadings.

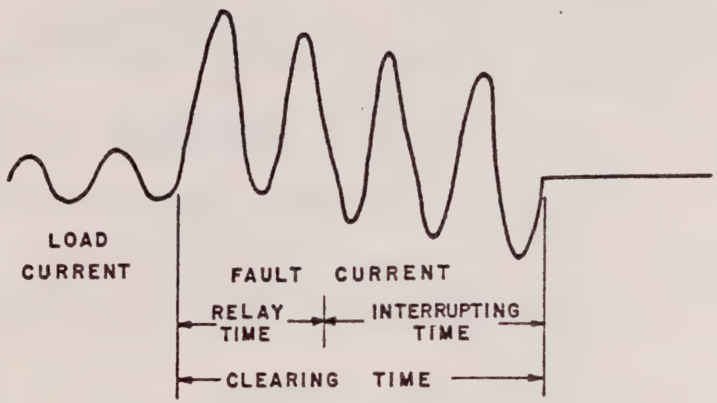
12.8 Short Circuits

Short circuits occur when the insulation from one or more phases of an element fails to ground or to another phase causing a large current to flow in the path created by the failure. This is commonly called a fault. It is essential that the short-circuited element be rapidly disconnected from the system to maintain system stability, to minimize personnel hazard and to minimize thermal or mechanical damage. The breakdown of the insulation may be caused by:

- voltages in excess of the insulation strength (eg., lightning or switching surges)
- design defects
- deterioration of the insulation from age, mechanical damage, contamination etc.,
- maintenance or operating errors
- failure of various components and contact by foreign objects

The removal of the faulted element requires a protective relay system to detect that a fault has occurred, and to initiate the opening of circuit breakers which will isolate the faulted element from the system. The time

taken to remove the fault from the system, known as the clearing time, is made up of the relay time and the interrupting time. The relay time is the time from the initiation of the short circuit current to the initiation of the trip signal to the circuit breaker. The interrupting time is the time from the initiation of the trip signal until the flow of the current through the breaker has been interrupted.



On Ontario Hydro's 230 and 500 kV system normal relay times are 15 to 35 milliseconds (1 to 2 cycles) and circuit breaker interrupting times 30 to 70 milliseconds (2 to 4 cycles).

The short-circuit current through an element may be only slightly greater than the normal load current or it may be 10 times or even a 100 times greater than load current. Each piece of equipment selected for use on the system must be carefully chosen so that it can withstand short-circuit currents without damage throughout its useful life.

Typically, as a system grows and more generation and lines are added, short-circuit levels increase. It is essential that maximum short-circuit levels be estimated for a number of years in advance so that equipment will not require early replacement. If the short-circuit current exceeds the capability of the equipment, it poses a serious hazard to safe and reliable operation.

Short-circuit currents are highest in those parts of the system where there is a concentration of infeeds from the generating stations. On the Ontario Hydro system the highest short-circuit currents occur in the Toronto-Hamilton area. Short-circuit currents in other areas tend to be significantly lower.

controls. The generator has two sets of windings, one set wound on the stator and the other on the rotor. The rotor winding is excited by direct current and is referred to as the field winding. The turbine drives the rotor and the magnetic field produced by the rotor winding induces, in the stator windings, alternating currents which are supplied to the load. The frequency of the ac in the stator depends on the speed of the rotor, i.e., the electric frequency is synchronized with the mechanical speed and this is the reason for the designation "synchronous machine". The field winding is supplied from an exciter which may be a dc generator or a controlled rectifier. The voltage of the exciter is varied by an automatic voltage regulator to control the terminal voltage of the synchronous generator. The exciter and the automatic voltage regulator are part of a control system which is called the excitation system.

When two or more generators are connected in a power system they must operate in synchronism, ie., at precisely the same average speed. The two generators are in some ways analagous to two cars speeding around a circular track and joined by a strong rubber band. If the two cars run side by side, the rubber band will remain intact. If one car temporarily speeds up with respect to the other car, the rubber band will stretch and tend to slow down the faster car and speed up the slower car. If the pull on the rubber band exceeds its strength it will break and the one car will pull away from the other car thereby breaking synchronism. The pull on the rubber band is related to by the angular displacement between the two cars.

In the case of two synchronous generators connected in a power system, the power transferred from one generator to the other is a function of the angle between their rotors, ie., rotor angle, and has the characteristics shown on Figure 12-12. Under normal operating conditions, the rotor angle is such that no power is transferred from one generator to the other. As the rotor angle increases, the power transferred increases until it reaches a maximum value. The magnitude of this maximum power depends on the impedance of the system connecting the generators, being greatest when the impedance is lowest.

Normally the mechanical output of the turbine closely matches the electrical output of the generator and the speed of the generator remains constant. If a fault occurs close to one of the generators, its voltage drops and its electrical power output is drastically reduced. The mechanical output of the turbine then exceeds the electrical output of the generator and the excess mechanical power causes the rotor to speed up and the

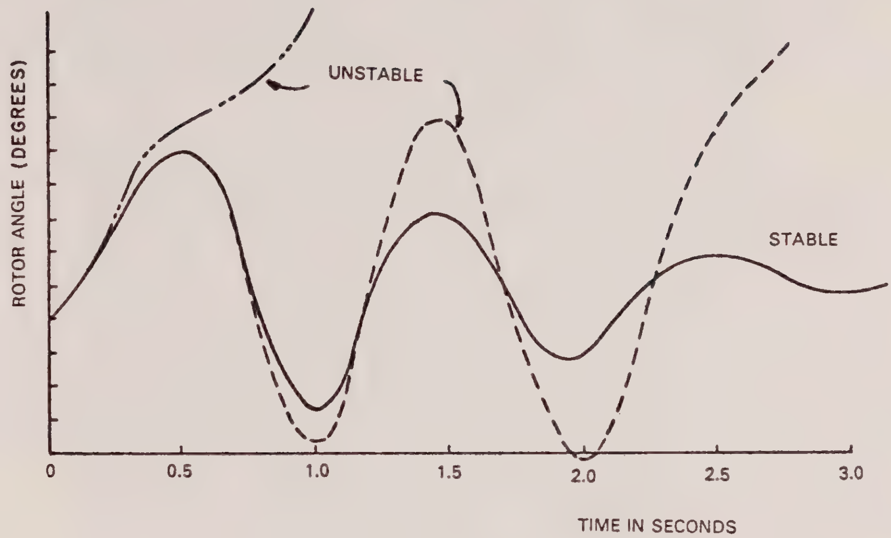
rotor angle to increase. When the fault is removed, the greater rotor angle causes power to be transferred from one generator to the other and if sufficient energy can be transmitted between generators, the generators will remain in synchronism. A strong transmission system between the two generators is analogous to a strong rubber band between the two cars above.

If the initial disturbance is too severe, or if the transmission cannot carry enough energy to ensure synchronism then the generator will pull out of step. When the generator pulls out of step, it must be quickly removed from the system or it will cause severe voltage disturbances, may cause other generators to pull out of step and may cause damage to the generator and other equipment.

For convenience in analysis and for gaining useful insight into the nature of the stability problem, it is usual to classify power system stability in terms of the following categories:

> <u>Transient Stability</u> is concerned with the response of the system to a large disturbance, such as a fault on the transmission system. Transient stability is normally concerned with the behaviour of the system up to about 2 seconds following the disturbance.
>
> The nature of the behaviour of a synchronous machine for stable and unstable situations is illustrated on page 12.0-29. The Figure shows the rotor angle following a sudden disturbance for a stable, and for two unstable situations. In the stable case, the rotor angle increases to a maximum, then decreases and oscillates with decreasing amplitude until it reaches a steady-state. In the unstable cases, the rotor angle continues to increase until synchronism is lost or it continues to oscillate with increasing amplitude until it loses synchronism in one of the subsequent swings.

Line Number



<u>Dynamic Stability</u> is concerned with the response of the system to small disturbances which continually occur in the operation of a system. This response is very dependent on the characteristics of the excitation system used. The use of supplementary stabilizing signals in the excitation system provides a means of improving dynamic stability. In fact, for most system arrangements it is possible to design and install an excitation system which will completely eliminate dynamic stability problems.

Ontario Hydro uses an excitation control scheme with the stabilizing signal derived from turbine-generator shaft speed. Initially, the scheme was developed for hydraulic units and was later applied to thermal units also. The possibility of exciting torsional oscillations of the turbine generator shaft system had to be eliminated before the scheme could be applied to thermal units. This type of excitation control is now a standard feature for all new generating units.

The power system stability problem is one of keeping the interconnected synchronous machines in synchronism. Since it is the network that provides for power flow between generators and loads and between different generators, the strength of the transmission network is the primary factor in influencing stability. However, the characteristics of the generating units and the associated controls also have significant effects on stability. For any given system, there is a maximum amount of power that can be transferred from one part of the system to another due to stability considerations. The critical value of power above which the system is unstable and below which it is stable, for specified disturbances, is called the stability limit.

A. <u>Methods of Improving Transient Stability</u>

Methods of improving transient stability attempt to minimize the difference between the input mechanical power and the output electrical power of the generators, during the fault period and immediately after. The various methods of achieving this are discussed in the following:

<u>Transmission System Reactance</u>

Reduction of reactance of the various elements of the transmission system improves transient stability by increasing the restoring power. Reactance can be reduced by adding transmission circuits. Another method is the use of bundled conductors. Reduction of leakage reactances of transformers also contributes to the reduction of the effective reactance.

For a given transmission configuration an effective method of reducing the system reactance may be the use of series capacitors to partially compensate for the inductive reactance of the lines. However, certain limitations and restrictions exist which often make their application unattractive. Because of the large ratio between fault current and normal load current, it is usually necessary to short circuit or bypass the series capacitors, during the fault period. Hence their beneficial effect is absent until they are reinserted. Also, there is the possibility of introducing oscillations which can cause severe damage to the turbine-generator shaft.

<u>Shunt Reactive-Power Compensation</u>

Shunt reactive-power compensation, capable of maintaining voltages at selected points of transmission system, can improve system stability by

increasing the flow of restoring power among interconnected generators. Synchronous condensers or controllable static compensators can be used for this purpose. Synchronous condensers are used by Ontario Hydro to improve system stability, in addition to providing general system voltage control. As explained in section 12.5 static compensators have not been used by Ontario Hydro.

Generator Characteristics

The generator characteristics have an important bearing on transient stability. Among the generator parameters which have the greatest effect are the machine reactance and the inertia constant. A higher generator reactance contributes to the overall system reactance and hence it is desirable to keep the reactance as low as possible. A lower inertia constant results in greater rotor speed and angular deviations for a given disturbance. However for thermal units these parameters are primarily decided by other economic and reliability considerations involved in the design of the generating units. In fact, the trend in turbine-generator characteristics, as unit sizes become larger, is in an adverse direction from the standpoint of system stability. Large units tend to have higher percent reactance and lower inertia constants. Power system planners usually have to look for alternative means of improving stability to accommodate generators with such characteristics.

High-Speed Excitation Systems

Significant improvements in transient stability can be achieved through rapid temporary increase of generator excitation. Increasing generator field voltage during a transient disturbance increases the flow of restoring power. The effectiveness of this type of control depends on quickly increasing the generator field voltage to the highest permissible value (referred to as ceiling voltage).

Thyristor exciters provide virtually negligible response time, and ceiling voltages which are limited only by generator rotor design considerations.

Ontario Hydro relies heavily on high speed excitation systems to ensure adequate stability performance of its system. Practically all new generating stations are equipped with thyristor excitation systems. In the excitation control scheme adopted by Ontario Hydro, the excitation system responds to signals

proportional to changes in terminal voltage and rotor speed. The terminal voltage signal in addition to providing voltage regulation action, drives the generator field to the ceiling voltage during a transient disturbance and thereby assists in improving transient stability. The rotor speed signal is used primarily for dynamic stability considerations. Pioneering work done by Ontario Hydro in the development and application of high speed excitation systems is reported in references 1, 2 and 3.

In some special situations it has been found to be beneficial to use a discrete signal proportional to the change in rotor angle, in addition to the continuous signals proportional to the terminal voltage and rotor speed. Reference 4 gives a description of the considerations that led Ontario Hydro to develop such a scheme.

Dynamic Braking

Dynamic braking uses the concept of connecting an artificial electrical load to the generation to increase its electric power output and thereby reduce the rotor acceleration. One form of dynamic braking involves switching-in shunt resistors during a transient disturbance so as to reduce the acceleration of the generator rotor. Ontario Hydro does not at present use this technique.

Generation Rejection

Generation rejection is another form of control for improving transient stability. It involves selective tripping of generating units for certain disturbances and transmission line outages. Rejection of part of the generation has the effect of reducing the excess power to be transferred and hence stability is improved. Since a generating unit can be tripped very rapidly, it is very effective in improving stability. Originally this technique was confined to hydraulic units which are more rugged than thermal units. It is now of necessity being extended to thermal generation as well, because of delays in obtaining transmission line routes.

When a thermal unit is suddenly disconnected from the system, it is subjected to sudden changes in mechanical and thermal loadings as well as electric loading. While the unit and its controls are designed to withstand such shocks, there is some possibility that the controls may not function

correctly and damage could result. Also thermal units are not designed for frequent full load rejection, and significantly increasing the number of full load rejections can be expected to increase unit maintenance requirements and reduce unit availability.

Fast Valving

A method applicable to thermal units, is rapid closing and opening of the turbine valves resulting in a sharp decrease and subsequent restoration of turbine mechanical power. This procedure is commonly referred to as fast valving and involves the actuation of the valves in a prescribed close-open cycle, upon receipt of a discrete signal from controls on the power system. In conventional configurations of steam turbines there are two convenient locations for such control, the main governor valves at the input to the high-pressure section of the turbine and the intercept valves at the inlet to the intermediate pressure or low-pressure turbine sections. Depending on how these valves are used to control the steam, a variety of possibilities exist regarding the implementation of fast valving schemes.

In one commonly considered scheme, only the intercept valves are very rapidly closed with subsequent full reopening after a short time delay. This method results in a fairly significant amount of reduction in turbine power and has minimum side effects on the rest of the steam system. A more pronounced temporary reduction of turbine power can be achieved through actuation of both governor valves and intercept valves. However the stresses imposed on the high-pressure section of the steam supply system are considered unacceptable on some units. This procedure of rapid closing and subsequent full opening of the valves is called momentary fast valving.

In some situations, due to the post-fault transmission system being weaker than the pre-fault system, it may be desirable to have the prime-mover power after being reduced rapidly, return to a value lower than the initial power. This leads to the concept of sustained fast valving. One approach is to provide for return of the governor and intercept valves to partial open positions, after their rapid closure. An alternative approach is to provide for rapid closure and partial opening of intercept

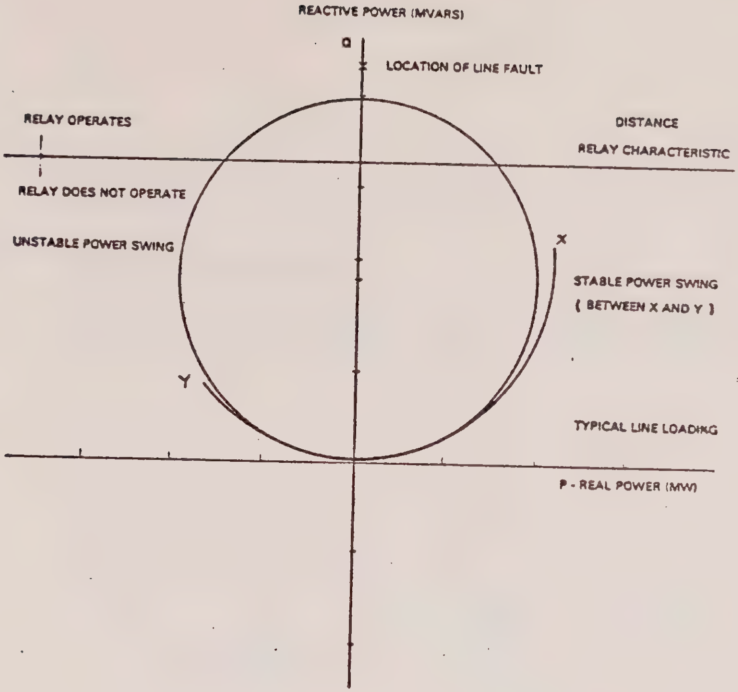


Figure 12-13

DISTANCE RELAY CHARACTERISTIC FAULT LOCATION AND
POWER SWING LOCI

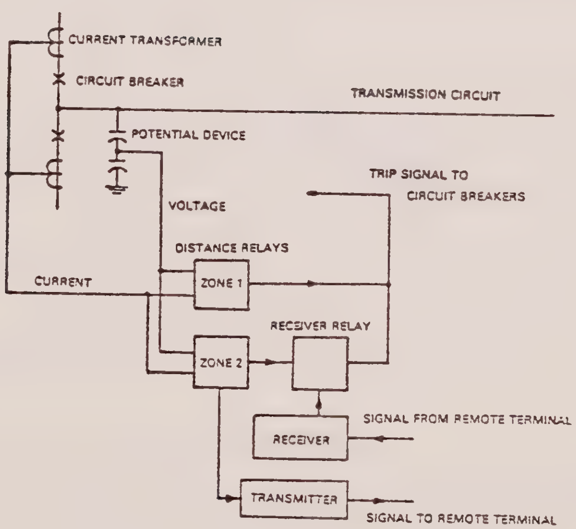


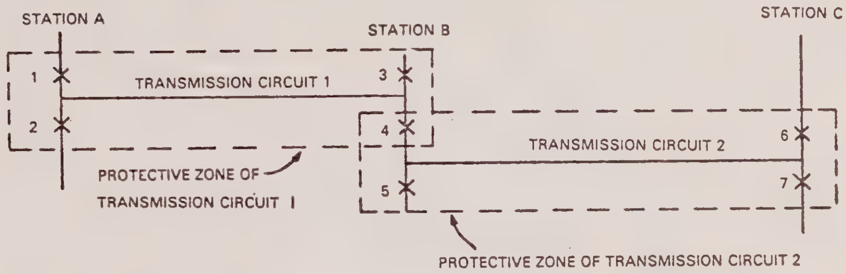
Figure 12-14

SIMPLIFIED DIAGRAM OF TRANSMISSION
CIRCUIT PROTECTIVE SCHEME

terminal has determined that the fault is on the circuit.

B. Protective Zone

The protective zones of two transmission circuits are shown by the dashed lines in the figure below.



CIRCUIT BREAKER 4 IS IN THE OVERLAPPING PROTECTIVE ZONES OF TRANSMISSION CIRCUITS 1 AND 2

In order to safely protect all power system equipment it is necessary to provide an overlap between two protective zones. The overlap in the protection is usually around a circuit breaker. If a fault occurs in the overlap it is necessary to open the circuit breakers in two adjacent zones. In the figure, the protective zones for two transmission circuits overlap circuit breaker 4 in Station B. A fault in the overlap is seen by the protective relaying schemes as a fault on both circuits 1 and 2 and will trip both these circuits.

C. Breaker Failure Protection

Relay protections are provided to determine if a circuit breaker has failed to clear a fault. In this event action is taken to clear the fault by tripping an adjacent zone. For example in the above figure if a fault occurs on transmission circuit 2 and breaker 4 fails to open, breaker failure protection will initiate opening of breakers 1, 2 and 3. This removes additional unfaulted equipment and increases the fault clearing time.

D. Performance of Protective Relaying Under Unfaulted Conditions

It is important that protective relays do not operate under normal circuit loading conditions or during power swings following a system disturbance where the system remains stable.

Figure 12-13 shows the location of normal circuit loadings, a stable power swing between X and Y and unstable power swings relative to the operating characteristics of a distance relay. In this illustration both the normal loading and the stable power swing are in the non-operating area of the relay. For the unstable power swing, the locus enters the operating area of the relay so that the circuit could trip for this condition. If one circuit trips, circuits in parallel will be called upon to carry additional loading and they too are likely to trip. When these cascade trips occur the system is likely to break up into a number of islands.

Under unstable conditions, the unstable system should be quickly disconnected from the main system, to protect equipment and to prevent the power swings from spreading the disturbance to a larger part of the interconnected system. Therefore some trippings are necessary and it is desirable that the trippings occur so that the load and generation in the island formed are close to being balanced. Unfortunately, it is not practical to separate at the desired locations for many unstable conditions.

12.11 Power Flow Distribution

In a high voltage network such as Ontario Hydro's, there are usually a number of transmission paths over which power can flow from the generation to the load. The power distribution among these paths is determined primarily by the reactance characteristics of circuits and transformers and by the magnitude and location of generation and loads. Where there are two or more transmission circuits in parallel, without shunt load, the power distributes approximately in inverse proportion to their length. This is generally desirable because it means that the power tends to take the shortest most direct route to the load and to minimize transmission losses. However, since the power distribution is determined by network characteristics over which there is limited control, circuit and transformer loadings can be such that some elements are overloaded while others with adequate capacity to carry the power are only partially loaded.

Series capacitors can be installed in transmission circuits to reduce their reactance and thereby obtain a better distribution of power flows. This solution is costly and has not been used by Ontario Hydro. Another means of controlling power flows is to install phase-shifting transformers. Such transformers introduce a controlled variable voltage in series with a circuit which can be used to control power flow. These transformers are also costly but permit a wide range of control which cannot be achieved by series capacitors. Such phase-shifting transformers have been installed in two interconnections with Manitoba, in one with New York and in one with Michigan.

Normally the power outputs of Ontario Hydro's generators are in balance with the electrical load plus losses on the Ontario Hydro system. When a large electric load is suddenly switched on the distribution of this load amongst the generators can be considered as taking place in four stages. Actually all of the stages are interdependent but it is easier to visualize them as four consecutive stages and approximately correct.

In the first stage, the additional load is distributed among the generators on the North American interconnected system, in approximately inverse proportion to the reactance between the load and the generators. This means that the generators closest to the load tend to pick up more load than more distant generators.

In the second stage, each generator tends to temporarily slow down. Generators with the greatest load in proportion to their capacity slow down most. At the end of this stage, the additional load is shared amongst the generators in proportion to their inertia. Generation with the largest inertia takes the largest portion of the load. Since Ontario Hydro's generation has only about 5% of the inertia of the North American grid, about 95% of the additional power requirements flow into the Ontario system from its interconnected neighbours.

In the third stage, the speed governors take over to alter the output of the turbines. At the end of this stage the additional power is distributed amongst the generators in accordance with generator capacity. Again about 95% of the power requirements will continue to flow into the Ontario system from its interconnected neighbours.

In the fourth stage, Ontario Hydro's load frequency control system which monitors system frequency and flow over the interconnections acts to bring the interconnection flows back on schedule. It does this by increasing the output of one or more generators in Ontario

until all the load increase is taken up by generators in Ontario.

The first three stages would take place in seconds while the fourth stage could require minutes to complete.

A fifth stage could take place if the operators found the generator loading to be unsatisfactory and took manual action to redistribute loadings amongst the generators.

12.12 Dynamic and Transient Overvoltages

Power equipment in addition to being subjected to the 60 hz voltage is also subjected to dynamic and transient overvoltages.

The 60 hz voltage prevails more than 99% of the time and is controlled within close limits as described in Section 12.5.

Dynamic overvoltages occur under contingencies such as a sudden loss of transmission and may last a number of seconds. They are primarily power frequency voltages which attain magnitudes of up to two times the normal system voltage.

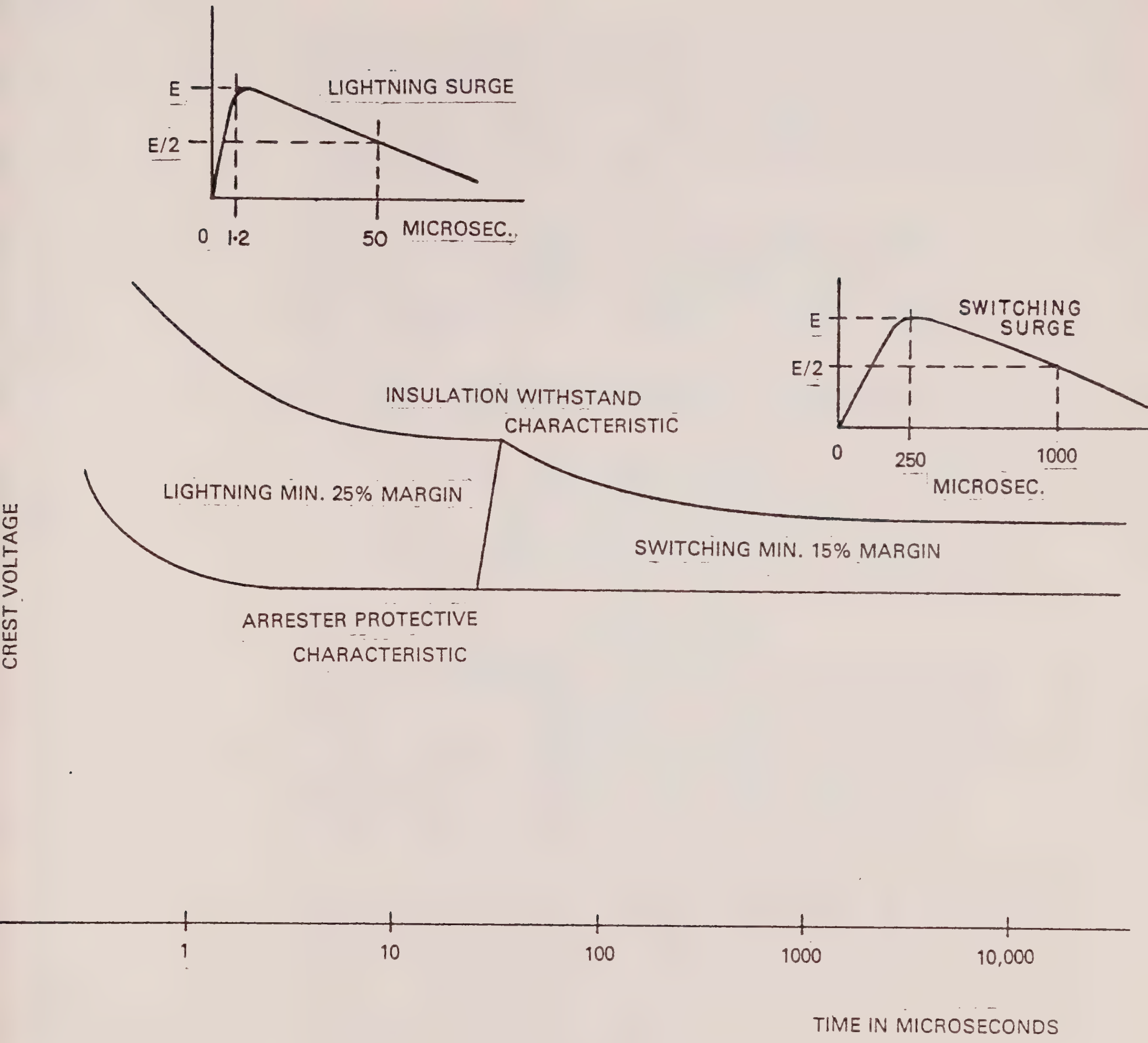
Transient overvoltages include switching and lightning surges. Switching surges occur when power equipment such as transformers, capacitor banks or transmission circuits are switched in and out of service. The resulting surges are heavily damped oscillatory waves. They have an infinite variety of shapes. For standard tests they are usually represented by a unipolar wave with a time to crest of 250 microsends and a time to decay to one-half crest of 1000 microseconds as shown in Figure 12-15. If not controlled the magnitude of switching surges can be up to about 4 times the crest of normal operating voltage.

Lightning strokes can cause flashovers of line insulators. The resulting surges can be represented by a unipolar wave but with a time to crest of only 1.2 microseconds and time to decay to one-half crest of 50 microseconds as shown in the Figure. Their magnitude may reach up to 6 times the crest of normal operating voltage.

Power systems are designed so that dynamic and transient overvoltages do not normally overstress equipment insulation, taking account of the following:

A. Volt-Time Characteristics of Insulation

The capability of power equipment such as transformers, breakers, SF6 bus duct etc. to



INSULATION COORDINATION CURVES AND SURGE WAVE SHAPES

FIGURE 12-15

The accepted protective devices against lightning surges at 115 kV and 230 kV transformer stations are simple, inexpensive, air gaps formed by two rod electrodes and known as the rod-gap. If voltages exceed their protective level, they flashover to ground to limit the voltages. Rod-gaps do not interrupt power-follow current after their operation and must be de-energized along with the equipment they protect to recover the insulation strength of the gaps. Also they do not provide as consistent a protection against surges as lightning arresters. Pipe gaps have been developed by Ontario Hydro to provide improved protection against lightning surges.

At generating stations and 500-230 kV transformer stations, lightning arresters which are capable of recovering their insulation strength after sparkover are used to protect insulation of major equipment. Since the arresters carry current for only a fraction of a cycle, the sparkover does not operate the protective relays and remove equipment from service. A 25% margin is normally provided between the arrester protective level and the equipment lightning withstand strength.

<u>Switching Surges</u>

No special effort is made to control switching surges on 115 kV and 230 kV lines. This is because a relatively high insulation strength is available at these voltage levels as a result of providing acceptable strength against lightning surges.

On the 500 kV network switching surges are more critical than lightning surges. Therefore a special effort is made to reduce the magnitude of switching surges. This is done by providing 500 kV circuit breakers with pre-insertion resistors, and by installing shunt reactors on some circuits.

The same protective devices that are used for lightning protection also provide protection against switching surges. A margin of 15% between the arrester protective characteristic and the insulation withstand strength is used.

12.13 Communications System

A communications system is required to transmit information between stations, to carry out four functions for the protection and control of Ontario Hydro's bulk power system. These are as follows:

- Protective Relaying

  The protective relaying functions are discussed in Section 12.10.

- Automatic Generation Control

  It is necessary to be continually changing the output of the principal generating stations on the system as the load demand is changing. The automatic generation control keeps the total of all tie line loadings at the desired power schedule and allocates changes in load among the generation so as to reduce production costs.

- Monitoring of the Power System Status and Power Flows

- Voice Communications

  The latter two functions are discussed in Section 12.15.

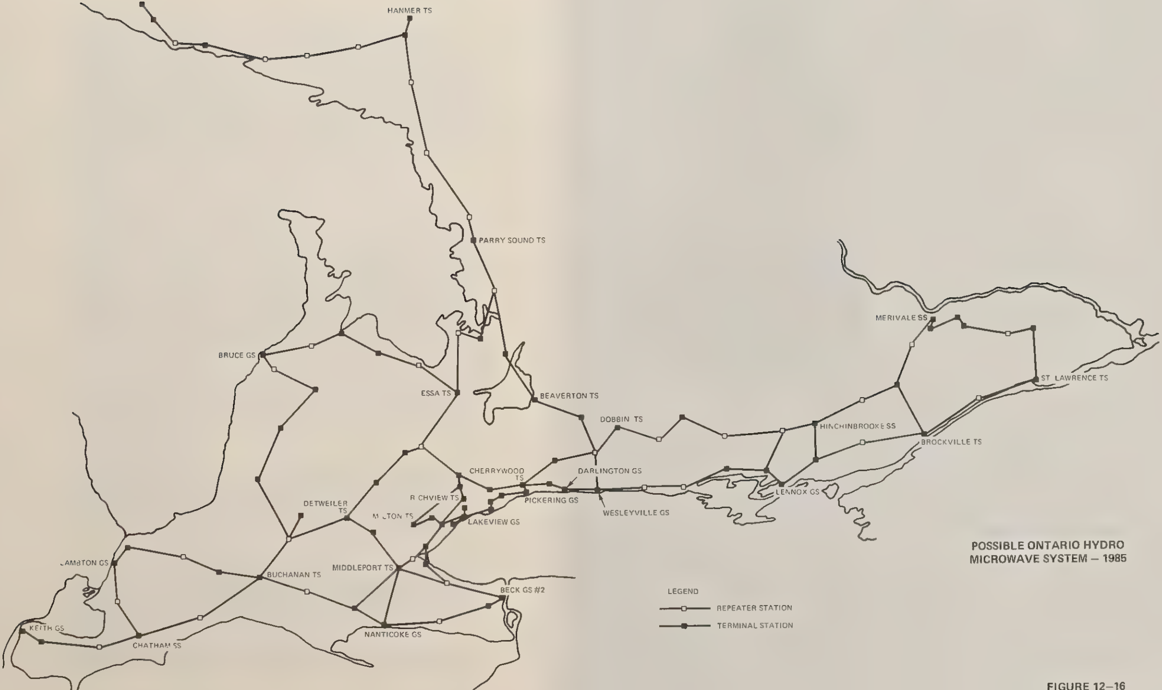
Technical Requirements

High reliability is needed in the communications system used for protective relaying. Seventy-five percent of the communications channels are used for the transmission protective relaying.

Prior to 1969, relay signals for the protection of 500 kV and 230 kV circuits were usually transmitted via high frequency carrier channels on the power lines. This type of communications is known as power-line carrier. For some channels telephone circuits were employed.

About 10 years ago, it became evident that power-line carrier could not accommodate the future requirements as the power system expanded. The amount of information that could be transmitted was limited by the frequency spectrum available to power-line carrier. On the other hand, the use of microwave transmission would increase the number of communications protection and control channels available by several orders of magnitude. It was decided, therefore, to install a microwave system in southwestern Ontario and the Toronto-Hamilton area where the power-line carrier was inadequate and to progressively expand microwave system into other parts of the power-system as the power-line carrier became inadequate. Ontario Hydro now has an extensive microwave communications system as shown in Figure 12-16.

Two protection schemes are provided for every major system component such as a generator, transformer or transmission



POSSIBLE ONTARIO HYDRO MICROWAVE SYSTEM — 1985

FIGURE 12–16

line. These are kept as separate and independent of each other as is practical, so that failure of one will not affect the other. Two separate communications facilities are provided for line protections. The present southern Ontario microwave system of Ontario Hydro consists of a number of closed loops or rings. Protection information sent between two stations on a ring is transmitted in both directions around the ring and the maximum practical separation between terminal equipment in a station for the two directions is provided. In the microwave system, the total communications channel time is less than 15 milliseconds) i.e., less than 1 cycle on a 60 hertz basis).

12.14 Methods of System Analysis

Up to about 15 years ago, system analysis methods to predict power flows for planning and operating purposes involved use of an electric analogue or model of the system. Typically 115 volts on the analogue would represent 115,000 volts on the system and 1 watt would represent 1 MW on the system. As power systems increased in size and complexity, analogues became impractical to use and today almost all complex analyses make use of high-speed digital computers. It is unlikely that it would have been practical to develop today's complex power systems if large digital computers had not been available.

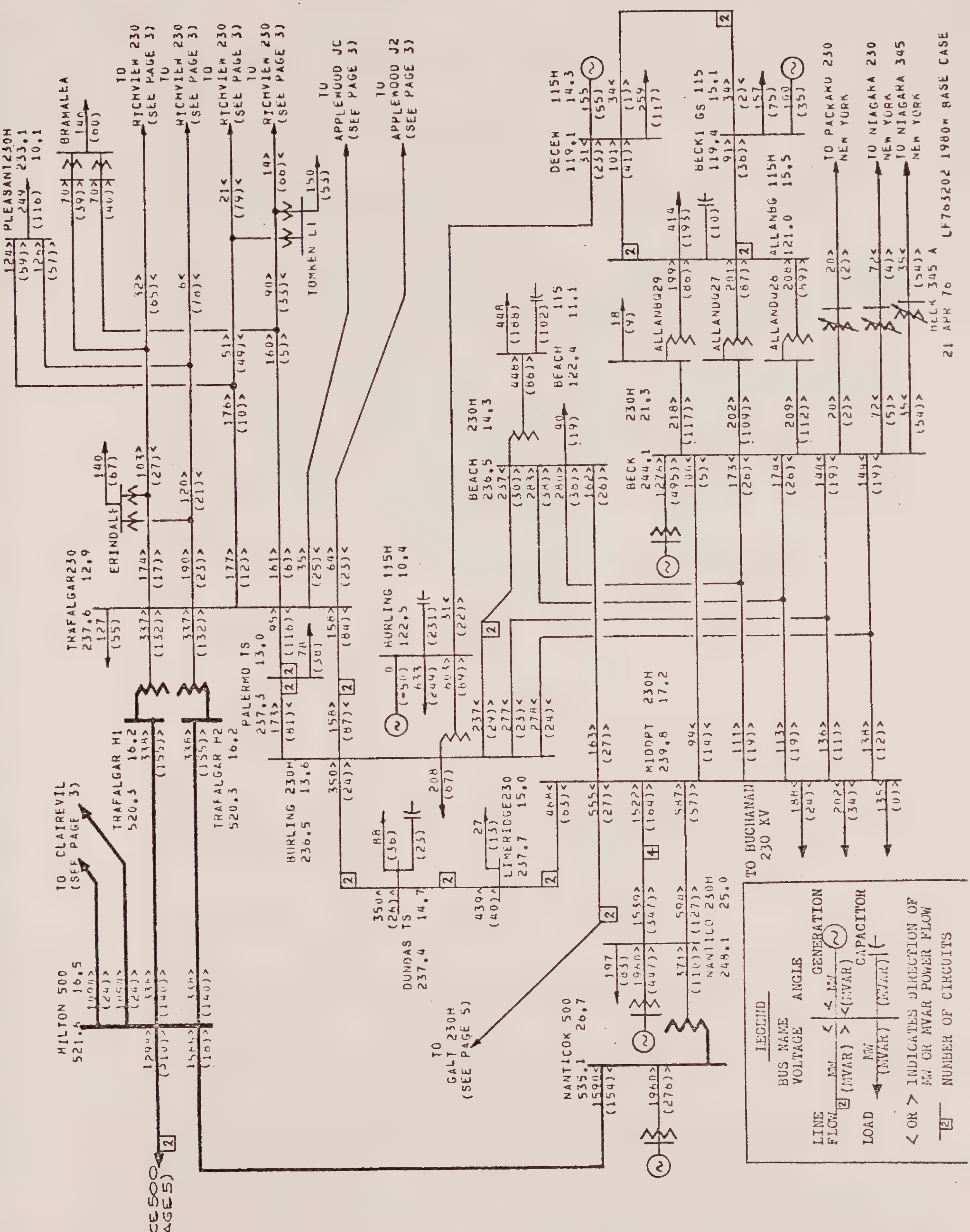
A large number of computer programs are available to aid in the planning and operation of the power system. Some of the major programs used in system analysis are discussed in the following.

Load Flow Program

Load-flow programs are the most frequently used programs for system studies. The basic input comprises the electrical connections, generator, transformer and transmission circuit electrical characteristics, the power and reactive power to be supplied at each load point and the generator power output and voltage.

The load flow shows the expected power and reactive power flow in hundreds of circuits and transformers and the voltage at hundreds of system supply points. The output information can be automatically plotted on a system single-line diagram. Part of the output of a load flow program is plotted in Figure 12-17.

The program used by Ontario Hydro can solve a power system with up to 1000 station buses and 2500 interconnecting circuits. Computer running time on a large high-speed



LOAD FLOW PLOT

FIGURE 12-17

computer for a large power system is about 5 to 10 minutes.

Transient-Stability Program

For one load flow, it may be necessary to perform many transient stability runs for different types of faults and different fault locations.

A transient stability program is considerably more complex than a load flow program because it must solve the dynamic equations associated with acceleration or deceleration of the generator-turbine rotating masses and with the excitation and governor control systems. This is in addition to carrying out a series of load flow analyses separated by discrete time intervals of say .05 seconds to determine the power flows and voltages existing in the network as the generator angles swing relative to each other. Transient stability analyses normally analyse the first 3 seconds of system time requiring some 60 load flow analyses. The computer running time is about 30 to 45 minutes.

The program provides the time variation of many quantities such as:

generator rotor angles
generator power
bus voltages
circuit power flows
excitation system voltage
turbine power

The program can also monitor power swings on specified circuits comparing these with the protective relaying characteristics of the circuit. If a power swing enters the protective zone of the line relays, the program "alarms" the relay operation in the output data.

Small-Signal Dynamic-Stability Program

This is a program used to determine the stability of a multi-machine power system for small disturbances. The program is used for the following purposes:

- to determine dynamic stability limit of power systems under different operating conditions.

- to evaluate the effect of machine, transmission system, and excitation system parameters on dynamic stability.

Line Number

Short-Circuit Program

Programs are available to calculate short-circuit currents and voltages as required for the design of protective and other equipment.

Switching-Surge Program

Ontario Hydro's switching-surge program represents up to 400 buses, and up to 700 elements. Between 35 and 100 generating sources may also be represented depending on whether the system is being studied on a three phase or single phase basis.

One version of the program is capable of representing the closing of a three phase circuit breaker (or switch) with various distributions of closing time and sequence in each of the three phases relative to a "target" or ideal closing sequence. The programs will automatically examine 100 cases of various closing times and will provide probability curves of the highest voltages expected. It will repeat the "worst" or highest case with complete results, including automatic plots of the voltage time curves.

Transformer-Aging Program

Based on known test data and insulation aging characteristics of transformers, the hottest temperature spots in the transformer windings can be determined, for various assumed overloads. Also the aging of the insulation can be calculated with reasonable accuracy. The temperature rises vary with the amount of overload, and the "history" of loading prior to the overload. Such knowledge of overload capacity enables rational decisions to be made about the timing of transformer replacements and new transformer installations.

Data-Management Program

As the amount of information required in load flow and stability analysis increases, the management of such data in orderly and easily available files becomes vital. These data files form a necessary link in all types of analytical calculations, and the updating and security of such information must be carefully monitored.

Induction-Motor Program

The stability or dynamic performance of induction motors becomes important when large induction motors (greater than 5000 HP) form a major percentage of a load. The torque-speed characteristics of both the motor and the

driven mechanical loads can be studied, as well as the characteristics of the supply facilities. An example of its application is the study of the supply to the heavy water plants at Bruce.

12.15 System Operation

The function of the operating staff is to supply a changing load demand by means of varying transmission and generation resources. The system must be operated safely with a high degree of reliability, with the lowest practical production cost, and within environmental constraints.

The thousands of elements such as generators, transmission circuits, transformers, and circuit breakers, plus the essential auxiliary systems including the voice communications system and the protective relay systems, constitute a highly complex power supply system. These elements are subject to failure and must be regularly switched out of service for maintenance and repair.

The generators and their associated turbines and auxiliary equipment are not only subject to forced and maintenance outages but their operation is also affected by stream flows and the availability of fuels. As a result, no unit or plant can sustain a continuous maximum output and quite frequently units are required to be shut down. The capability and output of any plant, therefore, are variable.

The load is also variable from hour-to-hour, day-to-day and month-to-month with the maximum annual demand occurring during the day in December and the minimum occurring usually during the night in July.

The operating function is carried out by a multi-tiered organization consisting of the System Control Centre located in Toronto, 8 Regional Operating Centres, and many Station Operating Centres located across the Province.

The overall direction of the bulk power system including the coordination of the outputs of all generating plants and the actual setup or arrangement of system components is from the System Control Centre. This Centre is staffed on a full-shift basis, and is responsible for:

- matching generation with load on a system-wide basis

- maintaining adequate and properly distributed generation reserves

- meeting environmental constraints

- monitoring and controlling the system setup and transmission loadings to insure the required level of security

- using available power resources to achieve low production cost

- directing the restoration of the power system following a disturbance

Direction from the Control Centre is mainly through the Regional and Station operating staff. Their duties include:

- performing switching operations to remove or return equipment to service following planned or forced outages

- loading, controlling and unloading generating units

- monitoring, logging, and adjusting system parameters (such as voltage)

The functions of the System Control Centre in operating the bulk power system have been described briefly above. The operation of the system has become increasingly complex as a result of the development and growth of the generation and transmission facilities.

Rigorous security standards, designed to reduce the probability of widespread system disturbances, are incorporated into the planning process and must be observed and applied in the operating environment of changing combinations of load levels, generation patterns, interchange transactions, weather conditions and equipment outages. This has required the development and maintenance of a large number of operating instructions for the guidance of the control supervisors in monitoring the power system and has increased the work load of the control supervisors significantly.

With the introduction of complex control systems, frequent operating adjustments are required to meet design performance. For example, the widespread application of generation rejection for transmission system contingencies requires continued monitoring of system quantities at many locations, analysis and checking against criteria, and the selection of units to be tripped.

Economy of scale in the development of the system has resulted in larger capacity elements. Operating alternatives must be more carefully considered because of the increased consequences of operating decisions.

The introduction of a wide variety of generating sources for base, intermediate, or peak loading, has greatly increased the number of possible operating modes for the system.

The volume of data to be assimilated, the volume of background information to be available for reference, the calculations to be performed with high accuracy, and the complex relationships to be assessed make it increasingly difficult to respond appropriately to power system variations.

Consideration of these and other factors led to development of the DACS system. The application programs in DACS process power system data and provide the control supervisor with automatic monitoring and quickly calculate results for use in the selection of operating modes.

The Power System Operations Division works closely with the Transmission System Planners. During the planning phase, alternative systems are reviewed to determine whether they satisfy operating requirements. Once facilities have been placed in service their performance is monitored and the planners are advised of any operating difficulties. In addition, unanticipated problems may arise from time to time and the solution to such problems is developed jointly by the System Planners and Power System Operations staff.

The continuing contact between the Operations and Planning staff provides useful information for the planning of future transmission projects.

12.16 Selection of Transmission Voltage

Planning studies to establish a voltage level for incorporating generation on the Moose River System, some 240 miles north of Sudbury, were begun in the late 1950's. At that time 230 kV was Ontario Hydro's highest standard voltage, 345 kV had been in use in the United States and 460 kV was being considered for use there. The alternative voltage levels of 345, 400 and 460 kV were considered for incorporating the Moose River generation. These studies showed that 400 and 460 kV were equal in cost and were less costly than 345 kV. The higher level of 460 kV was chosen on the basis that:

- It would have a greater margin of safety and stability.

- It was considered within the capabilities of North American manufacturers.

- It was more likely to become a North American Standard than 400 kV.

- It would be more useful in future in southern Ontario.

In 1959 Ontario Hydro established a test project at Coldwater to obtain data needed for 460 kV line design. Considerable important research work was done at that project, particularly in regard to corona losses and radio interference.

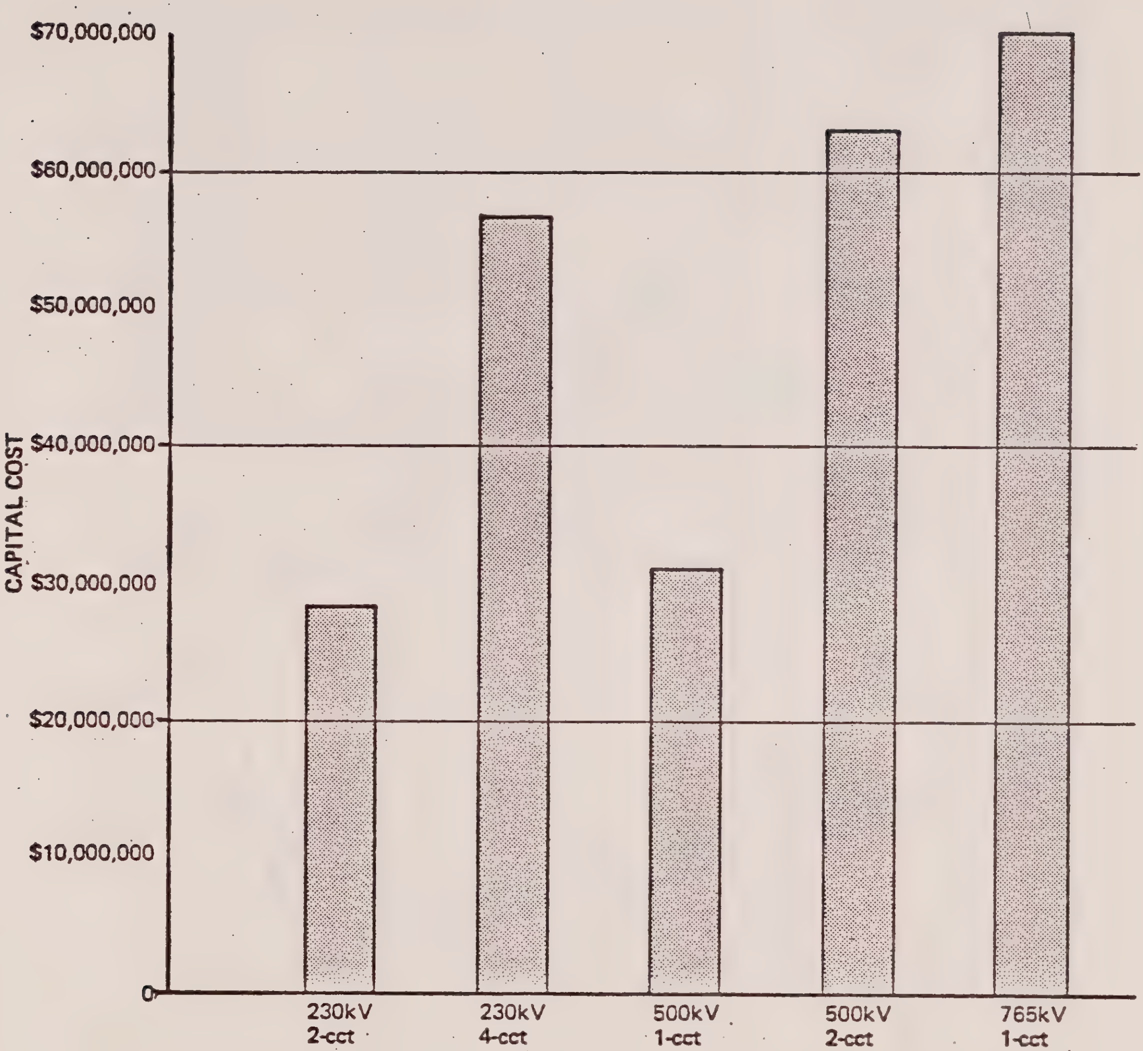
When 500 kV nominal, 550 kV maximum was chosen as an international standard, Ontario Hydro was able to uprate the 460 kV system to the new standard without major design changes.

Selection of an appropriate system voltage depends upon many factors but the principal factors are the amount of power to be transmitted and the distance the power is to be transmitted. In Ontario 80% of the load is located south of an east-west line running through Parry Sound and about 40% of the load is located in the Toronto-Hamilton area. The Great Lakes and their connecting rivers which provide a source of cooling water for generating stations are relatively close to all the major load centres. It therefore appears likely that in the future the average transmission distance from the generating stations to the load centres will be less than one hundred miles. This contrasts with the conditions in the Province of Quebec where the transmission distance to Montreal from the Manicouagan-Outardes complex is 360 miles, from the Churchill Falls development 720 miles and from the James Bay development about 600 miles.

Studies of future voltage levels made by system designers throughout the world have usually indicated that a new voltage level should be approximately double the existing highest transmission voltage. A voltage level of less than this does not usually provide sufficient advantages to justify a change. On the other hand unless special circumstances are involved, the higher initial capital costs of a voltage level much greater than twice the existing level cannot usually be justified by future savings or other advantages.

The transmission capabilities of 230 kV, 500 kV and 765 kV circuits was discussed in Section 12.4 and typical values are shown in Figure 12-8.

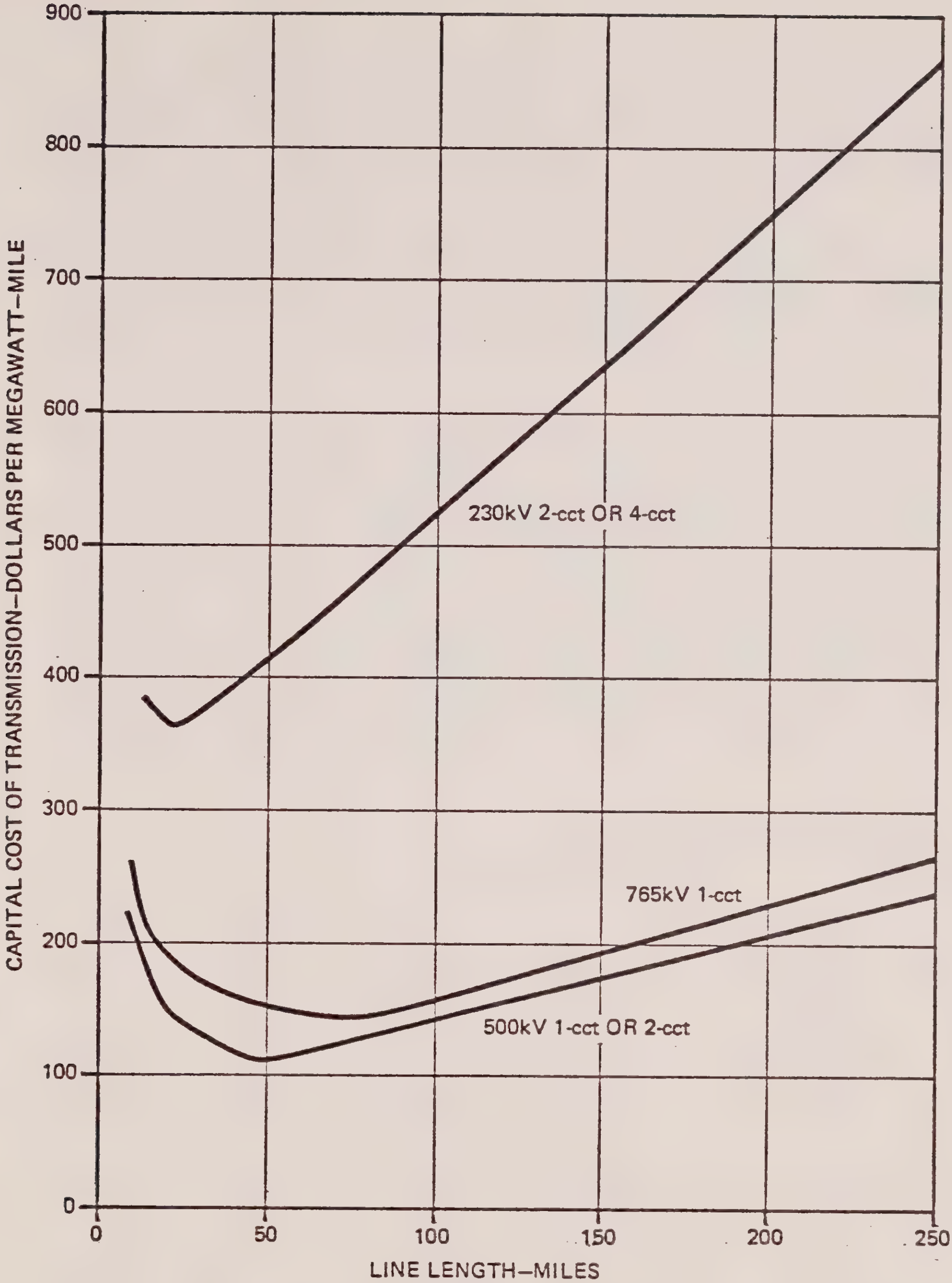
Figure 12-18 shows the initial capital cost required for 230 kV, 500 kV and 765 kV single and multiple circuit lines, 100 miles long, Figure 12-19 shows how the initial



INITIAL
CAPITAL COST OF TRANSMISSION
100 MILES OF TOWER LINE
(INCLUDING PROPERTY COSTS)

(1976 DOLLARS)

FIGURE I-2-18



INITIAL
CAPITAL COST OF TRANSMISSION
LINES PER MEGAWATT–MILE
VS
DISTANCE

(INCLUDES TERMINAL COSTS)

FIGURE 12–19

cost per megawatt-mile of transmitted power varies with distance for the three voltage levels assuming each circuit is loaded to the capability shown in Figure 12-8. Figure 12-19 indicates that there is a significant cost saving in using a 500 kV or 765 kV voltage level on the assumption that the circuits are loaded to their capability. The differences shown in Figure 12-19 between 500 kV and 765 kV lines are not large enough to show a strong preference for either voltage. Greater differences might occur in the study of a specific facility where all the design parameters could be carefully selected to reduce costs.

The following table shows how the 3 voltage levels compare in the use of land. The 500 kV and 765 kV levels are some 2 to 8 times more efficient per MW of transmitted power than 230 kV when comparing the area used by the tower base. Using this criterion, the 500 kV line is the most efficient of the towers considered. When compared on the basis of area of right of way the 500 kV and 765 kV towers are up to 3 times more efficient than a 230 kV line. The comparison does not include 765 kV 2-circuit towers because such towers would be extremely massive and costly and are unlikely to be used in the early stage of developing a 765 kV system. All 765 kV systems use 1-circuit towers.

Comparison of Land Use

			Area for 100 Mi		Area for 100 Mi per MW	
Voltage KV	Type of Tower	Right of Way Width Ft.	Right of Way Acres	Tower Base Acres	Right of Way Acres	Tower Base Acres
230	2-cct	110	1333	11.88	2.09	0.0186
	4-cct	130	1576	14.56	1.24	0.0114
500	1-cct	220	2667	5.58	1.06	0.0022
	2-cct	250	3030	11.88	0.615	0.0024
765	1-cct	310	3758	25.47	0.759	0.0051

The transmission criteria adopted by the Northeast Power Coordinating Council, of which Ontario Hydro is a member, require that a system be designed with sufficient transmission to maintain stability with one circuit out of service and subsequent loss of a tower line (1-circuit or 2-circuit). The criteria also require that for normal power transfers the system be operated to maintain the stability of the interconnected power systems for loss of

any 1-circuit or 2-circuit line. For emergency transfers, the criteria require that the system be operated to maintain stability for loss of one circuit. Application of these criteria results in the capabilities for short lines (i.e. up to 50 miles) shown in Figure 12-20.

Figure 12-20 shows that if the objective is to obtain the highest power transmitting capability while minimizing the number of rights of way and lines the 500 kV, 2-circuit line is significantly better than the 230 kV 2-circuit and 4-circuit and 500 kV and 765 kV 1-circuit lines.

Based on the foregoing considerations, Ontario Hydro has concluded that 500 kV is the appropriate voltage level for the future bulk power transmission network because:

- There is a satisfactory balance between the capital, operating, maintenance cost, land use and the future power requirements of the system.

- It matches the existing 500 kV system which was constructed for incorporating the Moose River system and for which Ontario Hydro has a great deal of successful design, operating and maintenance experience.

The choice between the use of 1-circuit 2-circuit 500 kV lines is evaluated separately for each addition to the 500 kV system.

12.17 Direct-Current Transmission

Direct current (dc) systems were of considerable importance in the nineteenth century, when the low voltage systems built by Edison and the high voltage system built by Thury were in existence. However the simpler design of ac rotating machines and the ease of changing voltage levels with transformers gave ac systems a considerable advantage. Today electric power systems throughout the world are almost exclusively ac.

Dc systems have a number of potential advantages over ac systems and these have led to their use in a number of specialized applications.

The forerunner of the modern high voltage direct current (HVDC) system was installed between the Swedish mainland and the island of Gotland in 1954. This scheme used mercury arc valves in the converter stations to convert the power from ac to dc and from dc to ac. The dc power was transmitted between the mainland and the island over a submarine cable using the sea as a return path. Since

Firm Capacity in Megawatts
Line Length up to 50 Miles

Criterion	Tower Type	Number of Lines in Parallel 1	2	3
Loss of 1 cct	230 kV 2 cct	470-1050	1410-3150	2350-5250
	230 kV 4 cct	1410-3150	3290-7350	5170-11550
	500 kV 1 cct	0	3700	7400
	500 kV 2 cct	3700	11100	18500
	765 kV 1 cct	0	5380	10760
Loss of 1 Line	230 kV 2 cct	0	940-2100	1880-4200
	230 kV 4 cct	0	1880-4200	3760-8400
	500 kV 1 cct	0	3700	7400
	500 kV 2 cct	0	7400	14800
	765 kV 1 cct	0	5380	10760
Loss of 1 cct + 1 Line	230 kV 2 cct	0	470-1050	1410-3150
	230 kV 4 cct	0	1410-3150	3290-7350
	500 kV 1 cct	0	0	3700
	500 kV 2 cct	0	3700	11100
	765 kV 1 cct	0	0	5380

FIGURE 12-20

1954 a number of schemes using mercury-arc valves have been installed (Figure 12-21).

In 1970, the first high capacity scheme using thyristors was installed as part of the Gotland scheme. The thyristor is a solid-state controlled rectifier which performs the same function as the mercury-arc rectifier. In 1972, the first all-thyristor, high-capacity, dc tie was installed at Eel River in New Brunswick to provide a link between the New Brunswick and Hydro Quebec systems. Since that time, almost all dc systems have used thyristors in place of the mercury arc valve. Figure 12-22 gives the dc projects based on thyristors which have been commissioned or are under construction.

The recent availability of suitable high-capacity thyristors resulted in more flexibility in designing HVDC systems, and it appears that their use will result in a significant improvement in the reliability of converter stations.

From Figures 12-21 and 12-22 it is seen that the main applications where dc has been used are as follows:

- Long underwater cable crossings where ac schemes are impractical or more costly.

- Long distance transmission without intermediate taps where dc is preferred considering cost, stability and other factors.

- Asynchronous interconnection between two systems where ac ties would be impractical because of stability problems or a difference in the nominal frequency of the two systems.

- High capacity underground cable for supply to the centre of an urban area.

A. Description of a DC System

The main components of a typical HVDC system consist of a bipolar dc line or bipolar cables, and two converter stations as shown on page 12.0-53.

DC TRANSMISSION PROJECTS BASED ON MERCURY-ARC VALVES

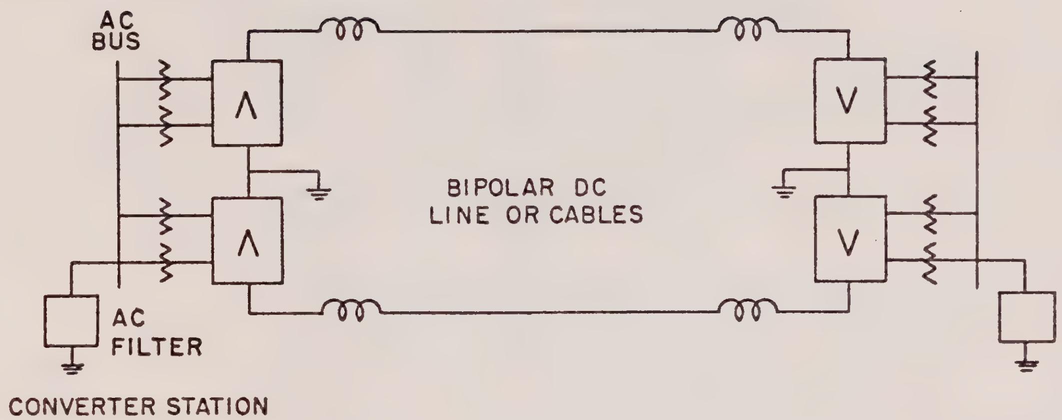
Project Name	Project Location	Commissioning Year	Power Transmitted (MW)	dc Voltage kV	Transmission Distance (Mi) Overhead	Transmission Distance (Mi) Cable	Main Reason for Choosing dc
Gotland	Sweden	1954	20	100	-	60	Sea Crossing
English Channel	England France	1961	160	±100	-	40	Sea Crossing, Asynchronous Link
New Zealand	New Zealand	1965	600	±250	354	25	Sea Crossing
Konti-Skan	Denmark	1965	250	250	53	54	Sea Crossing
Sakuma	Japan	1965	300	2 x 125	-	-	Asynchronous Link
Volgograd -Donbass	U.S.S.R.	1965	750	±400	292	-	Long Distance, Stability
Sardinia	Italy	1967	200	200	180	72	Sea Crossing
Vancouver Island	Canada	1968-1969	312	260	25.2	17.5	Sea Crossing
Pacific Intertie	U.S.A.	1970	1,440	±400	846	-	Long Distance
Nelson River	Canada	1972-1977	1,620	±450	555	-	Long Distance, Stability
Kingsnorth	England	1973	640	±266	-	52	Long Underground Cable, No Increase of Short-Circuit Current

FIGURE 12-21

DC TRANSMISSION PROJECTS BASED ON THYRISTOR VALVES

Project Name	Project Location	Commissioning Year	Power Transmitted (MW)	dc Voltage kV	Transmission Distance (Mi) Overhead	Transmission Distance (Mi) Cable	Main Reason for Choosing dc
Gotland	Sweden	1970	10	50	-	60	Long Sea Crossing
Eel River	Canada	1972	320	80	-	-	Asynchronous Link
Cabora Bassa	South Africa	1975 1976-78	970 1,940	±266 ±533	894	-	Long Distance
Inga-Shaba	Zaire	1976	560	±500	1,056	-	Long Distance
Tri-State Stegall	U.S.A.	1976	100	50	-	-	Asynchronous Link
Vancouver Pole 2	Canada	1976	370	280	25.2	17.5	Sea Crossing
Skagerrak	Denmark	1976-77	500	±250	74.5	81	Sea Crossing
Square Butte	U.S.A.	1977	500	±250	456	-	Long Distance
Coal Creek	U.S.A.	1978	1,000	±400	409	-	Long Distance, Stability
Nelson River 2	Canada	1978 1981-82	900 1,800	±450	555	-	Long Distance, Stability

FIGURE 12-22



One of the converter stations is operated as a rectifier in which ac is converted to dc and the other as an inverter in which dc is converted to ac. Normally a converter station is designed to operate in either mode since there is no major difference in the components required.

The main components of the converter station are:

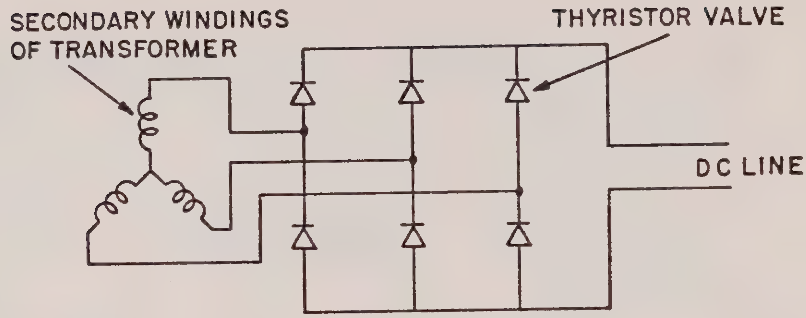
- valves which perform the rectification or inversion function

- transformers which provide the connection between the valves and the ac power system

- filters comprising reactors and capacitors to limit harmonics to an acceptable level as well as providing reactive power

- in some cases synchronous condensers to provide reactive power and acceptable ac waveforms

The usual bridge connection for a six-valve bridge in a converter station is shown on page 12.0-54.



B. Comparison of AC and DC Systems

General comparisons of ac and dc systems serve primarily to indicate applications where dc transmission would warrant consideration. Specific applications would require detailed investigation.

Advantages of DC

The principal advantages of dc transmission are outlined in the following:

Overhead Lines

For comparable power - transmitting capability, HVDC lines have fewer conductors, and shorter, less costly towers.

Underground or Underwater Cables

With ac underground or underwater cables the permissible distance between terminal stations is quite limited because, at some critical length, the cable becomes loaded with reactive power. The critical length depends on the voltage and type of cable. For a 500 kV ac cable, for example, it is about 15 miles. This distance limitation does not exist with dc cables.

Also losses are lower so that dc cables of a given capability are smaller and less costly than comparable ac cables.

Ground Return Currents

Most HVDC installations use ground or sea electrodes so that if one pole of the bipolar line is faulted, one half of the dc power can be delivered over the remaining pole using the earth or sea as a return path.

The use of ground or sea return improves the reliability of the dc system.

Dc currents between widely separated stations are usually spread over a wide cross section of the earth so that the dc current density is extremely low at any point except in the vicinity of the electrode. Problems in the vicinity of the ground electrodes are avoided by carefully selecting their location. Dc ground currents can cause problems and careful investigation is required before installing a system which requires ground currents for extended periods. In some installations, ground current flow is permitted for a short time only. Potential problems are:

- corrosion of underground metallic structures particularly pipelines

- change in underground water level due to electro-osmosis

- dc currents entering the ac power system through the grounded transformer neutrals

- interference with low voltage railway signalling systems.

Stability

Since the dc link provides an asynchronous connection between the two points of an ac system, the link does not introduce stability problems. Therefore it is possible to:

- transmit power from remote generating stations without intermediate stations as may be required with ac systems.

- interconnect large systems with small capacity interconnections which would not be practical with ac interconnections.

Since the power flow through the dc link can be rapidly controlled, the dc link can be used as a means of improving the stability of the ac systems to which it is connected.

Short Circuits

A dc link does not contribute to short-circuit currents. This may be an important consideration at major load centres or other locations where short-circuit currents are high.

Disadvantages of DC

The principal disadvantages of dc transmission are as follows:

Initial Cost

The following table provides an approximate comparison of the initial cost of the main ac and dc components for a system comprising overhead lines.

Approximate Initial Cost of ac and dc System Components

500 kV ac Line Rigid Tower Two Ground Wires					±450 kV dc Line Rigid Tower One Ground Wire			
500/230 kV Transformers both ends $/kVa	$/Mile	Size of Conductor in Bundle of Four (Kcmils)	Capacity in Amps Continuous	Capacity in Amps Emergency	$/Mile	Size of Conductor in Bundle of Two (Kcmils)	Capacity in Amps	Conver Equip both e $/kW
9	280,000	585	1,000	2,000	200,000	1843	1,800	75

Complexity

The dc terminal equipment is complex and the application of dc systems has been largely limited to point to point transmission.

Reliability

The following table shows the estimated outage and repair times for ac and dc installations and the actual outage and repair times experienced in 1974 for the Eel River and Nelson River installations.

For the conventional 500 kV ac installation, outage and repair times for the station equipment include such station equipment as line disconnect switches, circuit breakers, potential devices, current transformers and protective relaying. For the typical dc installation, the ac station equipment includes the above equipment plus converter transformer, and ac filters. The converter equipment includes such equipment as valves, anode reactors, converter and line control, line reactors, dc filters, potential and current devices and protective equipment. For the dc link, the outage rates are for a reduction in transmission capability to one half power. The number of times when there is a total loss of transmission capability is much lower. For the ac link the outage results in a total loss of transmission capability of the one circuit.

AC and DC System Components - Outage Rates and Average Repair Times per Outage*

Installation	Line		500/230 kV Transformer (Both Ends)		AC Station Equipment (Both Ends)		Converter Equipment (Both Ends)	
	Outages per Year per 100 Line Miles	Repair Time (Hours)	Outages per Transformer per Year	Repair Time (Hours)	Outages per Year	Repair Time (Hours)	Outages per Year	Repair Time (Hours)
Conventional 500 kV ac (Single circuit)	1	20	1	30	6	3	-	-
Typical dc Installation	1	20	-	-	14	40	8	6
Eel River Tie	-	-	-	-	8	15.72	5.5	3.82
Nelson River Link	.18	16.45	-	-	30	3.62	242	1.30

*Data for the Eel River and Nelson River installation are for 1974 and are taken from the report of the CIGRE Study Committee No. 14.

C. Use of DC in Ontario Hydro System

At present two applications of dc are under study, namely:

1. An asynchronous dc tie with Hydro Quebec. The tie might have an initial capacity of about 1000 MW with the capability to grow to an ultimate capacity of 3000 MW. Because of stability problems, an ac synchronous interconnection is not considered practical for this application.

2. An HVDC tie between the Ontario Hydro East and West systems. This tie would be 400 to 500 miles long and might have a capacity of 1000 to 2000 MW in the late 1980's. The ac alternative for this application would use 500 kV or 765 kV lines. HVDC is being considered for this application since the line crosses largely unpopulated areas and therefore there is unlikely to be a need for high capacity intermediate load supply.

12.18 Planning Process for a Transmission System

The process of planning a transmission system can be divided into four main steps:

- determine that additional facilities are required and their timing

- develop alternative systems for meeting the requirements

- evaluate the alternative systems

- recommend an alternative

Each of these steps is discussed below.

A. Determine that Additional Facilities Are Required and Their Timing

The requirement for and timing of additional facilities are determined by comparing the forecast peak and energy demands of the load with the capability of existing facilities to meet these demands. The capability of existing facilities and the requirement for new facilities are based, in addition to the matters discussed in this Memorandum, on the reliability criteria outlined in the Reliability Memorandum.

Recent experience indicates that eight or more years are required to plan and build a major transmission line. This time can be broken down approximately into the periods shown below. The times cannot be stated with certainty because they depend on the time taken for public participation hearings and government review, over which Ontario Hydro has only limited control. In certain cases time may be saved by carrying on two steps concurrently. The figures below are considered minimum times.

	Estimated Time Period Years
Gather data, carry out public participation procedures, prepare a report recommending a plan, including hearings on alternative plans and approval of a plan	2½
Gather data, carry out public participation procedures, prepare a report recommending a route, including hearings on route	2
Property acquisition, expropriation procedures, design and ordering of materials	2
Line construction (based on 100 miles)	1½
Total	8

Any study of the need for additional facilities which may include a new transmission line must be based on a forecast of conditions at least eight years in the future. If the additional facilities include a generating station on a new site, the lead time increases to 12 or 13 years. Additions or changes to existing transmission and receiving terminal facilities not requiring environmental review normally require a lead time of two to four years.

With these long lead times it is necessary for the system designer to look beyond the thirteen-year period in order to have available a full range of alternatives. The factors which determine the need, and the data used in assessing the alternatives, will be known less accurately with this long planning horizon. It is essential, therefore, to keep the lead time for alternatives short so that the forecast period is not unnecessarily lengthy; but on the other hand the study of future needs should extend far

enough into the future to permit all reasonable alternatives to be considered.

B. Develop Alternative Systems

There are a large number of potential solutions to most supply problems. In the interest of efficiency and arriving at recommendations in the available time, the planner may eliminate alternatives that are theoretically possible but are unacceptable because their lead time is too long, because they are too costly, or because the required technology is not sufficiently advanced.

The formulation of alternatives is a critical part of the process because:

- only a limited number of alternatives can be investigated in detail because of constraints of time and manpower.

- elimination of an alternative at an early stage may make it very costly or impractical to consider later.

- alternatives may be overlooked and there is no way of ensuring that all the feasible alternatives have been considered.

The development of practical alternatives requires a knowledge of the existing network, its capabilities and the provisions that have been made for its expansion. A long range planning framework for the expansion of the generation and transmission system is also required. This framework cannot be a detailed plan but should be a guide for formulating current plans. Without such a guide, planning would be done on a short term basis which may result in higher costs, lower reliability and greater environmental implications in the longer term.

Every alternative considered must be investigated to ensure it meets the following technical requirements:

- it provides acceptable reliability

- it remains within thermal, voltage, stability, relay and short-circuit limits for a wide range of normal and emergency operating conditions that can occur over the lifetime of the facilities. These limits and the techniques for investigating them are outlined in preceding sections.

Possible alternatives for providing increased transmission capability are:

- rearrange connections of existing facilities

- uprate or rebuild existing facilities

- install devices for voltage control such as series or shunt capacitors, reactors or synchronous condensers

- install facilities for generation rejection or load rejection schemes

- locate new generating stations and stage the development of new generating units to avoid or reduce the new transmission requirements

- build new interconnections or upgrade existing interconnections with other utilities

- build additional transmission lines or station facilities.

C. <u>Evaluate Alternative Systems</u>

Once a decision has been made on the alternatives to be studied, a great deal of data must be gathered in three major areas to permit their evaluation:

- environmental data - this is outlined in Memorandum on Transmission-Environmental, and includes the human environment

- cost data - such data normally include differences in capital, operating and maintenance costs, including power losses

- technical data - while each alternative considered must meet the minimum technical and timing requirements, there may be considerable differences among alternatives in technical factors such as:

  . flexibility to adapt to changes in forecast conditions

  . reliability

  . ease of operation

  . risk in the use of new technology

D. Recommend an Alternative

Because many differences between alternatives and the relative importance of these differences are difficult to quantify, the selection of an alternative for recommendation usually requires considerable judgement. There may be disagreements with the judgement used in arriving at a final recommendation.

12.19 Number of Lines on a Right of Way

When a study determines that several circuits are required between two stations, a decision must be made as to whether all these circuits should be on the same right of way or whether two or more rights of way should be used. This decision requires trade-offs between system reliability, land use, visual effects, and cost.

A decision must be made as to whether to use 1-circuit or multiple circuit construction. Use of 1-circuit construction results in the highest reliability. Multiple circuit construction usually results in a more acceptable combination of land use, visual effect, reliability and cost. On the Ontario Hydro system, use of 2-circuit construction is usually considered preferable at 500 kV. At 230 kV use of 2-circuit or 4-circuit construction is common. One-circuit construction has rarely been used in recent years.

When several lines are located close together the possibility exists that a single cause can affect several lines. Examples of such causes are:

- tornadoes
- conductor galloping
- insulator contamination due to local pollution
- malicious damage by gunfire
- impact by aircraft

The probability of occurrence is small, but loss of several lines could cause widespread customer interruption. For example, loss of all lines from a large generating station will result in loss of the output from that station. This will cause a shortage of system generation, and depending on the size of the station may result in interruptions to a large number of customers. Loss of all lines supplying a major load area may result

in a complete interruption for several days to customers in that area.

Using a separate right of way for each 500 kV tower line, would improve the reliability for the above occurrences but would have the following disadvantages:

- land requirements would be greater
- more property owners would be affected since there would be more routes
- towers would be visible from more locations
- the cost would likely be greater

Considering these disadvantages the level of reliability resulting from two or more lines on the same right of way may be acceptable in some circumstances. However, for large generating stations and major load areas complete dependence on one right of way would cause too great an adverse effect if all lines on that right of way were lost, and therefore some provision for a partial alternate supply is necessary.

On some rights of way particularly near urban areas it may be necessary to route 230 kV on the same right of way as 500 kV lines. The effect of this on reliability will depend on the use that is made of the 230 kV lines as part of the bulk power system. If the 230 kV lines are used only for area supply, the adverse effects resulting from loss of all lines on the right of way would not in general be significantly increased by the presence of 230 kV on the right of way.

12.20 Rebuilding or Replacing Existing Facilities

Ontario Hydro has acquired considerable land for its transmission lines and stations.

In the interests of reducing additional land requirements there has been considerable rebuilding of transmission lines to transmit more power over the same right of way. Examples are:

- Between Lakeview GS and Manby TS, an existing right of way, which was used for 60 kV lines at the turn of the century, was used in 1961 for 230 kV circuits which are adequate to carry the output of six Lakeview units.
- On the eastern outskirts of London an existing 115 kV line built in 1910 on a narrow right of way was

replaced in 1972 by a 230 kV steel-pole line to supply a new area supply station.

- Across northern Metropolitan Toronto, a 115 kV line built in 1950 was replaced in 1970 by a 230 kV line to augment the bulk power supply system.

Also many stations have been modified to increase their current carrying capacity or voltage, with little or no increase in property size.

However, there are limits beyond which rebuilding is not feasible. Some of the reasons that it may not be feasible to rebuild or replace lines on an existing right of way are:

- The existing facilities may have an important and continuing use.

- It may not be possible to rebuild or replace the existing facilities without interrupting customer load for an extended period.

- The existing right of way may be too narrow for the proposed new facilities, and widening may not be feasible.

- The use of an existing right of way for new transmission facilities may not be environmentally acceptable.

The planned 500 kV system, will take over some of the bulk power transmission function, thereby freeing capacity on the 230 kV system to meet the growing requirements of area supply. Thus most of the existing 230 kV circuits will have a continuing use, and it will not be feasible to remove them from service to permit the right of way to be used for 500 kV lines.

12.21 Future Trends

No revolutionary changes are foreseen in the nature of the bulk power transmission facilities that will be installed in the next 20 years. Certain technical developments, such as wireless transmission and cryogenic cables, are under study, but possibilities for achieving low cost underground or underwater cable transmission show greater potential. However it is unlikely that such developments will have advanced to the point of widespread commercial installation within the next 20 years.

It is expected that 500 kV will be the main bulk power transmission voltage for Ontario Hydro during this period

and that a higher voltage will not be introduced except possibly for certain long links or as part of interconnection facilities.

Continued evolutionary development is expected in the following areas:

- improvements in the reliability of and the relative cost of HVDC transmission.

- a reduction in the size of HV and EHV transmission towers along with improvements in the control of switching overvoltages.

- expansion in the use of SF6 stations.

- improved techniques for the analysis of future systems.

- improvements in control techniques for system protection and system stability.

- improvements in techniques for operation of the power systems.

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